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DELMARVA POWER & LIGHT COMPANY

PSC DOCKET

NO. 09-385F

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GAS COST RATE
NOVEMBER 2009 - OCTOBER 2010

(APPLICATION, TESTIMONY, AND SCHEDULES)

BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION

BRIEFING SHEET
2009/10 GAS COST RATE
DELAWARE PSC DOCKET NO. 09-___F

SUBJECT: Delmarva Power & Light Company's Application to establish its annual commodity cost rate and the demand cost rate components of the Gas Cost Rate (GCR) for the period November 1, 2009 through October 31, 2010.

CHANGE SOUGHT: Delmarva seeks to revise the GCR demand and commodity charge applicable to Service Classifications MVG and LVG, to revise the volumetrically applied GCR factors applicable to Service Classifications RG, GG, GL, and non-electing MVG, effective on November 1, 2009, with proration. The proposed GCR factors, compared to the presently effective charges, are shown below:

	Present		Proposed	
Rate Schedules	GCR Demand Charge	GCR Commodity Charge	GCR Demand Charge	GCR Commodity Charge
RG, GG and GL	N/A	109.812¢/ccf	N/A	93.959¢/ccf
Non-electing MVG	$8.5538/Mcf of Billing MDQ	$9.7555/Mcf	$9.5152/Mcf of Billing MDQ	$7.9076/Mcf
Electing MVG and LVG	$8.5538/Mcf of of Billing MDQ	Varies	$9.5152/MCF of Billing MDQ	Varies
Standby Service	$8.5538/Mcf of Standby MDQ	N/A	$9.5152/Mcf of Standby MDQ	N/A

REASONS FOR FILING: To establish the Gas Cost Rate factors for the twelve-month period November 2009 through October 2010. Section XX - Gas Cost Rate Clause of Delmarva's Gas Service Tariff requires, among other things, the submission of the Company's estimated annual gas costs for the twelve-month period beginning with the November billing month. Additionally, the Company proposes to reconcile and true-up actual versus estimated Commodity Cost Rate assignments for LVG and electing MVG customers.

EFFECTIVE DATE: Effective with usage on and after November 1, 2009, with proration.

IMPACT ON CUSTOMERS: Customers served under Service Classifications RG, GG, and GL will experience a 14.4% decrease in the level of the GCR. The effect on a residential space heating Customer using 120 ccf in a winter month would be a decrease of $19.02, or 10.2%, in their total bill. Customers served on Service Classifications GG and non-electing MVG would experience decreases on their winter bills within the ranges of 6.2% to 11.6% and 12.3% to 16.1% respectively, depending on load and usage characteristics.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION	**)**
OF DELMARVA POWER & LIGHT COMPANY	**)**
FOR APPROVAL OF MODIFICATIONS	**) PSC Docket No. 09-__F**
TO ITS GAS COST RATES	**)**
(Filed August 31, 2009)	**)**

APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR APPROVAL OF MODIFICATIONS TO ITS GAS COST RATES

Delmarva Power & Light Company ("Delmarva," or the "Company") makes the following application, pursuant to 26 Del. C. §§ 303(b) and 304, for approval of modifications to its gas cost rates. In support of its application, Delmarva states:

1. The Applicant is Delmarva Power & Light Company, New Castle Regional Office, 401 Eagle Run Road, P. O. Box 9239, Newark, Delaware, 19714. All communications concerning this Application should be sent to C. Ronald McGinnis Jr. at the above address, and to counsel for the Applicant identified in Paragraph 2.

2. Counsel for Delmarva is Todd L. Goodman, Delmarva Power & Light Company, 800 King Street, P. O. Box 231, Wilmington, Delaware 19899.

3. Delmarva requests approval of its proposed changes to its gas cost rates as follows:

	Present		Proposed	
Rate Schedules	GCR Demand Charge	GCR Commodity Charge	GCR Demand Charge	GCR Commodity Charge
RG, GG and GL	N/A	109.812¢/ccf	N/A	93.959¢/ccf
Non-electing MVG	$8.5538/Mcf of Billing MDQ	$9.7555/Mcf	$9.5152/Mcf of Billing MDQ	$7.9076/Mcf
Electing MVG and LVG	$8.5538/Mcf of Billing MDQ	Varies	$9.5152/Mcf of Billing MDQ	Varies
Standby Service	$8.5538/Mcf of Standby MDQ	N/A	$9.5152/Mcf of Standby MDQ	N/A

4. Delmarva also requests approval to reconcile and true-up actual versus estimated monthly Commodity Cost Rate assignments for sales under the Large Volume Gas service and for so-called "electing" customers taking service under the Medium Volume Gas classification.

5. Delmarva requests that its proposed GCR changes including the "true-ups" referenced in paragraph 4 above be made effective for usage on and after November 1, 2009, with proration.

WHEREFORE, Delmarva requests that the Commission issue an order directing the Company to publish the attached public notice, and, after hearing, approve the proposed gas cost rates and other requests described herein.

Respectfully submitted,

DELMARVA POWER & LIGHT COMPANY

By: ______________________

Todd Goodman
Delmarva Power & Light Company
800 King Street
P. O. Box 231
Wilmington, DE 19899
(302) 429-3786

DATED: August 27, 2009

EXHIBIT B

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION	**)**
OF DELMARVA POWER & LIGHT COMPANY	**)**
FOR APPROVAL OF MODIFICATIONS	**) PSC Docket No. 09-___F**
TO ITS GAS COST RATES	**)**
(Filed August 31, 2009)	

ORDER NO. ____________

AND NOW, to-wit, this ____ day of ________, A.D., 2009, Delmarva Power & Light Company, having, on August 31, 2009, filed the above-captioned Application with the Commission seeking approval to modify its Gas Cost Rates and for approval of related calculations to "true-up" costs and credits associated with the Large Volume Gas service and for "electing" customers under the Medium Volume Gas service;

AND, the Commission having determined, pursuant to 26 Del. C. §§ 303 and 304, that the proposed Gas Cost Rates and other requested modifications to its tariffs should be permitted to become effective for usage on and after November 1, 2009, with proration, and subject to refund pending evidentiary hearings and further review by the Commission;

Now Therefore,

IT IS ORDERED:

1. That pursuant to 26 Del. C. §§ 301 and 305, the application made by Delmarva Power on August 31, 2009, for modifications to its Gas Cost Rates and other tariff provisions be made effective as of November 1, 2009, with proration, subject to refund and evidentiary hearings to be held at a later date.

2. That ____________________ is designated as Hearing Examiner for this docket pursuant to the terms and provisions of 26 Del. C. § 502 and 29 Del. C. ch. 101 to schedule and conduct such public evidentiary hearings as may be necessary to develop a full and complete record concerning this matter, and to report to the Commission proposed findings and recommendations based on the evidence presented. ____________ is designated Rate Counsel for this matter.

3. That Delmarva Power shall give public notice of the filing of this application and of the Commission action thereon by publishing notice in the form attached hereto as Addendum to Exhibit "B" in two-column format, outlined in black in the legal classified sections of The News Journal on _______________, 2009, with proof of such publication to be provided to the Commission as soon as possible, but no later than the commencement of the evidentiary hearings concerning this matter.

4. That Delmarva Power is hereby put on notice that it will be charged the costs incurred in connection with this proceeding under the provisions of 26 Del. C. § 114(b)(1).

5. That the Commission reserves the jurisdiction and authority to enter such further Orders in this matter as may be deemed necessary or proper.

BY ORDER OF THE COMMISSION:

CHAIR

VICE-CHAIRMAN

COMMISSIONER

COMMISSIONER

COMMISSIONER

ATTEST:

SECRETARY

ADDENDUM TO EXHIBIT B

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION	**)**
OF DELMARVA POWER & LIGHT COMPANY	**)**
FOR APPROVAL OF MODIFICATIONS	**) PSC Docket No. 09-____F**
TO ITS GAS COST RATES	**)**
(Filed August 31, 2009)	**)**

PUBLIC NOTICE

TO: ALL NATURAL GAS CUSTOMERS OF DELMARVA POWER & LIGHT COMPANY

Pursuant to 26 Del. C. §§ 303 and 304, Delmarva Power & Light Company ("Delmarva" or the "Company") has filed an Application with the Delaware Public Service Commission ("Commission"). The Application requests a change in Gas Cost Rates as follows:

	Present		Proposed	
Rate Schedules	GCR Demand Charge	GCR Commodity Charge	GCR Demand Charge	GCR Commodity Charge
RG, GG and GL	N/A	109.812¢/ccf	N/A	93.959¢/ccf
Non-electing MVG	$8.5538/Mcf of Billing MDQ	$9.7555/Mcf	$9.5152/Mcf of Billing MDQ	$7.9076/Mcf
Electing MVG and LVG	$8.5538/Mcf of Billing MDQ	Varies	$9.5152/Mcf of Billing MDQ	Varies
Standby Service	$8.5538/Mcf of Standby MDQ	N/A	$9.5152/Mcf of Standby MDQ	N/A

In addition, the Application requests approval of the Company's proposal to reconcile and true-up actual versus estimated WACCOG assignments for sales under the Large Volume Gas service and for so-called "electing" customers taking service under the Medium

Volume Gas service. The Commission has permitted the proposed Gas Cost Rates and other rate related modifications to become effective as of November 1, 2009, subject to refund after evidentiary hearings and further proceedings. The Commission's action on this Application will be based upon the evidence presented at evidentiary hearings to be scheduled at a later date.

Any person or group wishing to participate formally as a party in this docket (PSC Docket No. 09-___F), with the right to submit evidence and to be represented by counsel must, in accordance with Rule 11, petition the Commission for and be granted leave to intervene in the proceedings in this docket. To be timely, all such petitions must be filed with the Delaware Public Service Commission at 861 Silver Lake Boulevard, Suite 100, Cannon Building, Dover, Delaware 19904 on or before _________ __, 2009. Petitions received thereafter will not be considered except for good cause shown.

Copies of the Application and the testimony and schedules the Company has filed in this docket are available for public inspection at the Commission's Dover office at the address set out above. Persons may also review copies of the Application and testimony by contacting the Division of the Public Advocate, Fourth Floor, Carvel State Office Building, 820 North French Street, Wilmington, Delaware at (302) 577-5077.

Individuals with disabilities who wish to participate in these proceedings or to review this tariff filing may contact the Commission to discuss any auxiliary aids or services needed to facilitate such review or participation. Such contact may be in person, by writing, telephonically, by use of the Telecommunications Relay Service, or otherwise.

The Commission's toll-free telephone number within Delaware is 1-800-282-8574. The Commission can also be reached at (302) 739-4333 and that number should also be used for Text Telephone ("TT") calls. Inquiries can also be sent to the Commission by Internet email to @state.de.us.

STATE OF DELAWARE)
) SS.
COUNTY OF NEW CASTLE)

On this 28th day of August, 2009, personally came before me, the subscriber, a Notary Public in and for the state and county aforesaid Gary R Stockbridge, Regional President of Pepco Holdings, Inc., a corporation existing under the laws of the State of Delaware, party to this Application, known to me personally to be such, and acknowledged this Application to be his act and deed and the act and deed of such corporation, that the signature of such Regional President is in his own proper handwriting, and that the facts set forth in this Application are true and correct to the best of his knowledge and belief.

Gary R Stockbridge

Gary R Stockbridge
President – Delmarva Region

SWORN TO AND SUBSCRIBED before me this 28th day of August 2009.

Kathy Ann S. Martin
Notary Public

My Commission expires: 3 | 1 | 2011

Appendix A

Appendix A consists of the following proposed tariff leaf revisions to the Company's Gas Service Tariff - P.S.C. Del. No. 5 - Gas:

- 42nd revised Leaf No. 37
- 38th Revised Leaf No. 38
- 21st Revised Leaf No. 39

RATES AND CHARGES

CORE SALES RATE LEAF

SERVICE CLASSIFICATION	BASE RATE	GAS COST RATE	TOTAL	BASIS
Residential Gas Sales Service ("RG")				
Customer Charge	$9.56	--	$9.56	per month
Commodity Charge	$0.421010	$0.93959	$1.360600	per CCF
Space Heating Commodity Charge 1/				
Over 50 CCF	$0.337840	$0.93959	$1.277430	per CCF
Environmental Surcharge Rider	$0.00175		$0.00175	per CCF
General Gas Sales Service ("GG")				
Customer Charge	$27.31	--	$27.31	per month
Commodity Charge				
First 750 CCF	$ 0.34975	$0.93959	$1.28934	per CCF
Over 750 CCF	$ 0.26125	$0.93959	$1.20084	per CCF
Environmental Surcharge Rider	$0.00175	--	$0.00175	per CCF
Gas Lighting Sales Service ("GL")				
(Estimated Usage - 15 CCF per month)				
Monthly Charge	$ 5.92	$ 14.09	$20.01	per gas light
Medium Volume Gas Sales Service ("MVG")				
Customer Charge	$419.27	--	$419.27	per month
Demand Charge	$ 13.39	$9.5152	$ 22.9052	per MCF of Billing MDQ
Commodity Charge 2/	$ 0.429790	$7.9076	$ 8.337390	per MCF
Environmental Surcharge Rider	$0.01748		$0.01748	per MCF
Large Volume Gas Sales Service ("LVG")				
Customer Charge	$634.58	--	$634.58	per month
Demand Charge	$ 8.247210	$9.5152	$ 17.762410	per MCF of Billing MDQ
Commodity Charge 2/	$ 0.103390	Varies	Varies	per MCF
Environmental Surcharge Rider	$0.01748		$0.01748	per MCF
Public Utilities Tax			5.00%	Charged on all non-exempt services, including the GCR
City of Wilmington Local Franchise Tax			2.00%	Charged on all non-exempt services, in the City of Wilmington, including the GCR

1/ Gas used by Customers with permanently installed gas-fired space heating equipment qualifies for the space heating commodity rate for all gas used in excess of 50 ccf for the billing months of October through May, inclusive.

2/ All LVG and "Electing" MVG Customers pay a monthly Commodity Charge GCR based upon the system Weighted Average Commodity Cost of Gas ("System WACCOG"). "Non-Electing" MVG Customers pay the annual GCR Commodity Charge listed here.

RATES AND CHARGES

CORE TRANSPORTATION RATE LEAF

SERVICE CLASSIFICATION	BASE RATE	NON-BASE RATE	BASIS
General Volume Firm Transportation Service ("GVFT")			
Customer Charge	$302.31		per month
Delivery Charge			
First 750 CCF	$ 0.349750		per CCF Redelivered
Over 750 CCF	$ 0.261250		per CCF Redelivered
Balancing Fee		$ 0.04242	per CCF of Imbalance Volumes
Environmental Surcharge Rider	$0.00175		per CCF
Medium Volume Firm Transportation Service ("MVFT")			
Customer Charge	$694.27		per month
Demand Charge	$ 13.39		per MCF of Billing MDQ
Delivery Charge	$ 0.429790		per MCF Redelivered
Balancing Fee		$ 0.4242	per MCF of Imbalance Volumes
Environmental Surcharge Rider	$0.01748		per MCF
Large Volume Firm Transportation Service ("LVFT")			
Customer Charge	$909.58		per month
Demand Charge	$ 8.247210		per MCF of Billing MDQ
Delivery Charge	$ 0.103390		per MCF Redelivered
Balancing Fee		$ 0.4242	per MCF of Imbalance Volumes
Environmental Surcharge Rider	$0.01748		per MCF
Standby Service ("SBS")			
Demand Charge		$9.5152	per MCF of Standby MDQ
Commodity Charge			Monthly System WACCOG per MCF (adjusted for losses and unaccounted-for)
Public Utilities Tax		5.00%	Charged on all non-exempt services, including the GCR
City of Wilmington Local Franchise Tax		2.00%	Charged on all non-exempt services, in the City of Wilmington, including the GCR

RATES AND CHARGES

NON-CORE RATE LEAF

SERVICE CLASSIFICATION	BASE RATE	MIN RATE	MAX RATE	NON-BASE RATE	BASIS
Flexibly Priced Gas Service ("FPS")					
Commodity Charge 1/		Varies	N/A		per MCF
No Notice Swing Charge	$ 0.15000				per MCF Redelivered
Medium Volume Interruptible Transportation Service ("MVIT")					
Customer Charge	$590.00				per month
Delivery Charge (2)					
Option 1	$ 1.30000				per MCF Redelivered
Option 2		$0.01	$3.27		per MCF Redelivered
Option 3	Negotiable				per MCF Redelivered
Balancing Fee				$0.4242	per MCF of Imbalance Volumes
Large Volume Interruptible Transportation Service ("LVIT")					
Customer Charge	$775.00				per month
Delivery Charge (2)					
Option 1					
First 5,000 MCF	$ 1.30000				per MCF Redelivered
Over 5,000 MCF	$ 0.36000				per MCF Redelivered
Option 2		$0.01	$1.00		per MCF Redelivered
Option 3	Negotiable				per MCF Redelivered
Balancing Fee				$0.4242	per MCF of Imbalance Volumes
Quasi-Firm Transportation Service ("QFT")					
Customer Charge	Negotiable				per Month
Demand Charge	Negotiable				per MCF of MDQ
Delivery Charge (2)	Negotiable				per MCF Redelivered
Balancing Fee				$0.4242	per MCF of Imbalance Volumes
Public Utilities Tax				5.00%	Charged on all non-exempt services, including the GCR
City of Wilmington Local Franchise Tax				2.00%	Charged on all non-exempt services, in the City of Wilmington, including the GCR

1/ Minimum Rate is the monthly system WACCOG plus losses and unaccounted-for, unless gas is acquired specifically for, plus $0.01 per Mcf.

2/ Minimum and maximum rates do not include the applicable $0.00000/Mcf charge on QFT, MVIT and LVIT.

MICHAEL S. PONCIA

DELMARVA POWER & LIGHT COMPANY

TESTIMONY OF MICHAEL S. PONCIA

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

CONCERNING THE NOVEMBER 2009 THROUGH OCTOBER 2010

GAS COST RATE

P.S.C. DOCKET NO. 09-   F

1. Q: State your name, position, and business address.

A: Michael S. Poncia, Director of Gas Delivery, for Delmarva Power & Light Company (the "Company" or "Delmarva"), 630 Martin Luther King Boulevard, P. O. Box 231, Wilmington, Delaware 19899-0231.

2. Q: Please state your educational background, employment experience and present job responsibilities.

A: I have a Bachelor and Master of Science Degree in Civil Engineering from Drexel University. I have worked for Pepco Holdings, Inc. ("PHI"), the parent of Delmarva and its affiliates for approximately 12 years in various capacities, including Process Manager, Customer Relationship Management, and Manager, Energy Markets. Prior to joining PHI, I worked for PECO Energy – Exelon performing a variety of engineering, project management, construction, and account management roles. In my current capacity as Director, I am responsible for all aspects of reliability, safety, planning, engineering, construction, and operations & maintenance for the regulated gas utility serving approximately 122,000 customers in Delmarva's New Castle County service territory.

3. Q: **<u>Have you previously testified before this Commission?</u>**

A: Yes. I testified in Docket No. 08-266F.

4. Q: **<u>What is the purpose of your testimony in this proceeding?</u>**

A: I am testifying on behalf of Delmarva supporting the Gas Cost Rate ("GCR") proposed to be effective from November 1, 2009 through October 31, 2010. Specifically, I will provide background regarding Delmarva's policy on the following matters:

1. The Company's strategy to mitigate the volatility of wholesale natural gas market prices;
2. Customer Communications and Budget Billing, and
3. The status of Docket No.08-266F.

5. Q: **<u>Who will submit direct testimony on behalf of the Company?</u>**

A: Three other witnesses will testify in support of the Company's Application. Mr. Philip L. Phillips, Jr., Manager of Gas Operations and Planning, will sponsor testimony regarding the development of the Gas Sales Forecast, the Loss Factor, the status of the Eastern Shore Natural Gas "E3" Project and certain provisions of the Proposed Settlement Agreement executed by the Parties in PSC Docket 08-266F. Mr. W. Thomas Bacon Jr., Director of Strategic Planning, Energy Supply, will present testimony with respect to the Gas Hedging Program, the estimated purchased gas costs, the revision of the balancing fee for transportation swing service. Mr. C. Ronald McGinnis Jr., Team Leader in the Regulatory Affairs Department, will present testimony with respect to the development of estimated recoverable firm gas costs, the derivation of the proposed GCR factors and related true-ups, and the projected recovery positions for the GCR periods ending October 31, 2009, and October 31, 2010, respectively.

6. Q: **<u>What are the proposed Gas Cost Rate factors for the 2009/2010 period?</u>**

A: The proposed Gas Cost Rates are designed to recover the total estimated level of firm gas commodity and demand expenses expected to be incurred by Delmarva during the 2009/2010 period, as well as to "true-up" for the projected under-recovery of actual gas costs during the 2008/2009 period ending October 31, 2009 by including those under-recovered amounts to be spread over the proposed 2009/2010 GCR.

The Company requests that the proposed GCR factors become effective with usage on and after November 1, 2009, with proration. The Company's proposed GCR factors for the 2009/2010 period are shown below, and are compared to the GCR factors presently in effect. Mr. McGinnis details the GCR factors calculated in accordance with the Company's Gas Service Tariff and their impact on customers' bills in his testimony.

<u>GAS COST RATE</u>

	Current	**Proposed**	**Change**
RG, GG, and GL	109.812¢/ccf	93.959¢/ccf	(15.853) ¢/ccf
LVG and MVG Demand	$8.5538/Mcf of MDQ*	$9.5152/Mcf of MDQ*	$0.9614/Mcf of MDQ*
Non-Electing MVG Commodity	$9.7555/Mcf	$7.9076/Mcf	$(1.8479)/Mcf
LVG and Electing MVG Commodity	Varies Monthly	Varies Monthly	N/A

- "MDQ" is Maximum Daily Quantity, which is a measure of a customer's contribution to peak demand.

7. Q: **<u>What is the impact to customers resulting from this filing?</u>**

A: During the heating season, a residential customer who uses approximately 120 ccf of natural gas will see a decrease in their overall bill of 10.2% or $19.02 per month, from $186.32 to $167.30. The impact on commercial and industrial customers will vary according to usage. However, the decrease supported in this filing for these customer classes will range from 6.2% to 16.1%

8. Q: **<u>Please discuss what actions the Company has taken to mitigate the volatility of natural gas wholesale market prices and to lessen the impacts on customers.</u>**

A: Delmarva uses several methods to mitigate the volatility of wholesale natural gas prices. The Company's Gas Hedging Program ("Program") was first approved in Docket 97-293F. In subsequent GCR proceedings, the Commission approved modifications to the Program as a result of a collaborative effort among the Company, Staff and DPA. The overall objective of the Program is to reduce gas commodity price volatility while limiting the firm customers' exposure to increases in the wholesale market price of gas. The hedging program involves entering into exchange traded and over-the counter financial agreements to lock in prices for a certain daily volume of gas for specified periods of time. Mr. Bacon addresses the operation of the Program in his testimony.

The Company also purchases natural gas during the summer and injects it into storage facilities for withdrawal during the five month winter season when demand is greatest. While the historical relationship of low summer and high winter market prices for natural gas is not as strong as in recent years, storage still is a very good hedge against wholesale price spikes that occur during the winter months.

9. Q: <u>**Please discuss Delmarva's Customer Communications Plan.**</u>

A: Delmarva has updated its annual natural gas communications plan to be shared with regulators prior to the beginning of the heating season. The plan serves as an outline of activities Delmarva plans to conduct to inform customers about the GCR and educate them on ways to use energy more efficiently at home or in the office. The plan discusses the reasons for the decrease in the GCR and explains changes to other gas rates such as the Environmental Surcharge. Activities in the plan include elements such as advertising, website messaging, community meetings, on-line home energy audit tools ("My Account"), and employee education. The plan also includes a timetable for meeting with various interest-groups who serve the needs of people who are most sensitive to increases in energy costs. In addition to the aforementioned, the plan also discusses activities planned to continue to promote the Company's Budget Billing Program.

10. Q: <u>**Please discuss the status of the Budget Billing Plan.**</u>

A: At the close of June, 2009, the Company had 122,129 gas customers and 14,087 of those gas customers are enrolled in the budget billing program. The Company's Communication Plan includes a series of activities designed to raise customers' awareness of the program. Activities in the plan include Bill Inserts which will contain information about budget billing and how to enroll. The Company also plans to print a budget billing promotional message on its billing envelope in the fall. Additionally, the Company plans to prominently display a budget billing promotion on the internet home page of Delmarva.com which will link to information about the program as well as enable customers to enroll on-line in addition to contacting our

Customer Service team. The planned Company advertising messages offering fall and winter energy conservation tips will also include information pertaining to budget billing. Customers will be encouraged to learn more about budget billing at community meetings and various Speakers Bureau events throughout the fall and winter heating season as a way to help manage their energy costs by spreading the costs of higher winter usage over a 12 month period.

The Company continues to support/sponsor such programs as the Good Neighbor Energy Fund, Consumer Energy Education Group and Low Income Summit. Certain programs provide financial assistance to customers, while others help educate customers about energy prices. The Company's Customer Services processes also continue to offer our customer's flexible payment arrangements to help them better manage payment requirements.

11. Q: <u>Please describe the 2008/2009 Gas Cost Rate proceedings.</u>

A: On August 29, 2008, Delmarva made its annual Gas Cost Rate ("GCR") filing. That filing was docketed as PSC Docket No. 08-266F. On January 26, 2009, the Company filed a Supplemental Application, requesting a reduction in its GCR commodity factors effective March 1, 2009. Subsequent to the discovery and the negotiation process, evidentiary hearings were conducted on April 17, 2009 and May 27, 2009. Prior to the May 27 hearing, an Agreement in Principle was approved by the parties and subsequently submitted to the Hearing Examiner. The Hearing Examiner's report recommending approval of the Settlement Agreement was submitted to the Commission on July 27, 2009. Final Commission approval is pending as of the date of this filing.

12. Q: What is Delmarva requesting of the Commission in this filing?

A: Delmarva respectfully requests that the Commission:

1. Approve the proposed Gas Cost Rate factors and balancing charge to become effective with usage on and after November 1, 2009, with proration;
2. Approve the reconciliation and true up of fuel revenue and margin amounts based on actual versus estimated monthly commodity cost assignments associated with the LVG and Electing MVG customers.

13. Q: Does this conclude your pre-filed direct testimony?

A: Yes, it does.

PHILILP L. PHILLIPS JR

DELMARVA POWER & LIGHT COMPANY

TESTIMONY OF PHILIP L.PHILLIPS JR.

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

CONCERNING THE NOVEMBER 2009 THROUGH OCTOBER 2010

GAS COST RATE

PSC DOCKET NO. 09 -____F

1. Q: Please state your name, position and business address.

A: Philip L. Phillips, Jr., Manager of Gas Operations & Planning, Delmarva Power & Light (Delmarva or the Company). Previous to assuming the duties of Manager Gas Operations & Planning in June, 2008, I held the position of Manager of Gas Engineering, Delmarva Power. My business address is 630 Martin Luther King Boulevard, PO Box 231, Mail Stop 88MK62, Wilmington, Delaware 19899-0231.

2. Q: What are your responsibilities in your role as Manager of Gas Operations & Planning?

A: As the Manager of Gas Operations and Planning, I oversee the day-to-day delivery of natural gas to the Company's customers. I am also responsible for related gas business and system planning activities.

3. Q: What is your educational and professional background and experience?

A: I am a graduate of the University of Delaware with a Bachelors Degree in Engineering Administration and am a registered Professional Engineer in the State of Delaware. I have been employed by Delmarva Power since 1970 serving in various engineering and management capacities including Gas Operations, Electric System

Operations, Substation, Meter and Gas Engineering. I am a member of American Society of Civil Engineers and National Society of Professional Engineers.

4. Q: <u>Have you previously testified before the Delaware Public Service Commission?</u>

A: Yes. I have provided testimony before the Delaware Public Service Commission in cases dealing with the Company's Environmental Surcharge Rider and Gas Cost Rate.

I have also worked with Commission Staff on a number of issues primarily associated with the administration of the Company's Gas and Electric Tariffs and on Natural Gas Pipeline Safety matters. I have prepared various engineering studies in support of previous filings and routinely participated in a various audits and reviews performed by Commission Staff.

5. Q: <u>What is the purpose of your testimony?</u>

A: The purpose of my testimony is to support the Company's Application for revisions to the Gas Cost Rate (GCR) proposed to be effective during the period November 2009 through October 2010. I am responsible for the overall development of Delmarva's gas sales and transportation volume forecast and for the lost and unaccounted for gas percentage utilized in the calculation of the proposed GCR. My testimony addresses those aspects of the application. Additionally my testimony will address the history of the Eastern Shore Natural Gas "E3" Project and certain provisions of the Proposed Settlement Agreement executed by the parties in PSC Docket 08- 266F.

Gas Sales Forecast

6. Q: <u>What level of sales does the Company forecast for the 2008-09 GCR period?</u>

A: As shown on Schedule PLP-1, for the 2009-10 GCR period the Company forecasts Firm Sales of 13,095,343 MCF and Transportation volume of 5,086,052 MCF, totaling a forecast Throughput of 18,181,395.

7. Q: <u>Is there any noticeable difference between the current forecast results and the forecast filed with the Commission in Docket 08-266F?</u>

A: Yes. As shown on Schedule PLP-1 Firm Sales are down 9.0%, Firm Transportation is down 19.1% and Firm Throughput is down 12.0 %.

When compared to the last years GCR 08-09 period forecast, most customer class forecasts reflect reduced sales for the upcoming GCR period as follows:

RES (-11.2%), RSH (-8.4%), GG (-1.7%), MVG (-37.1%), LVG (-55.0%), and LVFT (-28.1%). The GVTF sales forecast did increase 97.5% and the MVFT 11.6%. Overall the forecast Firm Sales are down 9.0% and Firm Throughput is down 12.0 %.

During the time period June 2008 through August 2009, fifty seven (57) Large or Transportation customer changes occurred. These include changes to MDQ, facility closings and rate changes. The net changes to the various large customer rates are summarized below.

	MVG	LVG		GVFT	MVFT	LVFT		MVIT	LVIT
June 09	44	4		13	26	16		5	5
Aug 09	30	2		30	33	14		5	4
Change	-14	-2		17	7	-2		0	-1

The forecast reflects the overall economic situation both nationally and in the Company's service territory.

8. Q: <u>Where there any changes to the forecast methodology this year?</u>

A: No. The forecast continues use of the methods utilized in prior years, specifically multi-variate econometric models for projection of sales and customer growth for the Residential, Residential Space Heat, and General Gas rate customers. These rate classes generally are designated the small classes. The volumes for MVG, LVG and GL were projected with the same basic approach that has been in use by the Company since 1999. These volumes continue to be forecasted deterministically on a customer by customer basis. If appropriate, monthly sales patterns for specific customers were adjusted to reflect recent customer contact information. Included changes reflect known contract, production or maintenance schedule changes, load additions or deletions, or other adjustments particular to each customer's activity.

Monthly sales in the Firm, Interruptible, and Quasi-Firm gas transportation ("FT", "IT", and "QFT") classes respectively developed in the same manner.

9. Q: <u>How was normal weather defined?</u>

A: The 30 year average of monthly Heating Degree Days on a 65 degree Fahrenheit base (HDD) was used consistent with the Commission's Order in Docket 03-127. The HDD history was collected by Gas System Operations at the Wilmington gas operations center.

Loss Factor

10. Q:<u>What is the percentage loss factor inherent in this year's annual GCR application?</u>

A: The percentage loss factor utilized in this year's filing is remains at 2.0%. The Company tracks average lost and unaccounted for gas using several time periods. The twelve month average through June 2009 was 2.50 %, the twenty four month average ending June 2009 was 1.93 % and the thirty six month rolling average was 1.78 %.

Eastern Shore Natural Gas E3 Project

11. Q: <u>Please provide the background related to the Eastern Shore Natural Gas E3 project and the current status.</u>

A: In July 2004 Eastern Shore Natural Gas (ESNG) held an Open Season that included 1) a traditional north to south pipeline capacity expansion to be in service in phases from 2006 to 2008 and 2) a Cove Point Bay Crossing project to be in service in 2009. ESNG proposed to develop, construct and operate approximately 75 miles of new interstate pipeline facilities (the E3 project) to transport natural gas from the existing Cove Point Liquefied Natural Gas terminal located in Calvert County, Maryland, crossing under the Chesapeake Bay into Dorchester and Caroline Counties, Maryland, to points on the Delmarva Peninsula. The facilities would interconnect with ESNG's existing facilities in Sussex County, Delaware. Delmarva submitted non-binding requests for additional service for parts of the combined project.

During 2005 ESNG decided to split the proposed project into two separate FERC applications. Thereafter, Delmarva and ESNG executed a Precedent Agreement for 19,600 Dth of traditional North to South pipeline delivery capacity expected to be phased in over three years beginning in 2006. ESNG established 60,000 to 80,000 Dth/day as an economic threshold for E3. Delmarva expressed an interest for 30,000 Dth / day if the capacity could begin as late as November 2011.

In February 2006 Delmarva and ESNG executed a Letter Agreement that provided in the event that the project is not certificated by the FERC and placed in service, Delmarva would share on a pro-rata basis in certain pre-certification costs up to a cap of $2 million by means of a FERC approved surcharge applied over a period of not less than 20 years.

In late May 2006, ESNG entered into Precedent Agreements (the "Precedent Agreements") with its customers, to provide additional firm transportation services upon completion of the E3 Project.

ESNG submitted a petition to the FERC on June 27, 2006, seeking approval of the preconstruction cost agreements contained in the Letter Agreements as part of a rate-related Settlement Agreement which would provide benefits to ESNG and its customers, including but not limited to:

(1) advancement of a necessary infrastructure project to meet the growing demand for natural gas on the Delmarva Peninsula;

(2) sharing of project development costs by the participating customers in the E3 Project;

(3) no development cost risk for non-participating customers.

In August 2006, the FERC issued a Letter Order approving ESNG's Petition. On September 6, 2006, ESNG submitted to the FERC proposed tariff sheets to implement the provisions of the Settlement Agreement. By Letter Order dated October 6, 2006, the FERC accepted the tariff sheets, effective September 7, 2006. On April 23, 2007, ESNG submitted to the FERC its request to commence a pre-filing process, and on May 15, 2007, the FERC notified ESNG that its request had been approved. The pre-filing process was intended to engage all interested and affected stakeholders early in the process with the intention of resolving all environmental issues prior to the formal certificate application being filed.

As part of this process, ESNG performed environmental, engineering and cultural surveys and studies in the interest of protecting the environment, minimizing any potential impacts to landowners, and cultural resources. ESNG also held meetings with federal, state and local permitting/regulatory agencies, non-governmental organizations, landowners, and other interested stakeholders.

As part of an updated engineering study, ESNG received additional construction cost estimates for the E3 Project, which indicated substantially higher costs than previously estimated. In an effort to optimize the feasibility of the overall project development plan, ESNG explored potential construction methods, construction cost mitigation strategies, potential design changes and project schedule changes. ESNG also held discussions and meetings with several potential new customers, who expressed interest in the E3 Project, but elected not to participate. On December 20, 2007, ESNG withdrew from the pre-filing process as a result of insufficient customer commitments for capacity to make the project economical.

ESNG continued during 2008 to explore potential construction methods, construction cost mitigation strategies, additional market requests, and potential design changes in its efforts to improve the overall economics of the E3 project.

12. Q: <u>What is the current status of the E3 Project?</u>

In May 2009 ESNG notified Delmarva of its election to terminate the Precedent Agreement dated May 31, 2006 based on the provision which provides a party the right to terminate the Agreement if a certificate application for the Project has not been filed with the FERC within 24 months after the data of the Agreement. ESNG also informed Delmarva that the Pre- Certification Costs totaled $3.17 million and that the resultant Company share was $1.56 million.

In May, based on the FERC approved Cost sharing Mechanism and tariff, ESNG began monthly surcharge billing of $21,495.

Docket 08-277F Proposed Settlement Agreement

13. Q: <u>Please provide a copy of the Proposed Settlement Agreement executed by the parties in PSC Docket 08-266F.</u>

A: A copy of the executed Proposed Settlement Agreement (the Agreement) associated with Docket 08-266F is attached as Exhibit PLP-2.

14. Q: <u>What is the status of PSC Docket 08-266F?</u>

A: The Hearing Examiner's report recommending approval of the Agreement was submitted to the Commission on July 27, 2009. In anticipation of potential Commission approval of the Agreement, the Company has taken initial steps to comply with the provisions of the Agreement.

15. Q: <u>Please provide an update on Provision B of the Agreement: Hedging</u>.

A: The Company has developed a transition plan to enable the implementation of the new hedging program guideline. This initial plan is based on the anticipated supply requirements associated with the sales forecast provided in PLP-1. The Company anticipates discussing this plan with the Parties during the upcoming 2009 Second Quarterly Hedge Report review meeting. Management of the Company's Gas Division will meet monthly with the individuals conducting the hedging program to review ongoing results.

Beginning with the third Quarter 2009 the Company anticipates filing its Quarterly Hedge Report within thirty (30) days following the close of the quarter.

16. Q: <u>Has the Company addressed, in prefiled testimony, commodity costs related to hedge purchases made in 2008 under the prior hedging program and the effect such purchases have on the 2009-2010 GCR ?</u>

A: Yes. This analysis is provided as part of Mr. Bacon's testimony, specifically questions 21 through 31.

17. Q: <u>Please provide an update on Provision C of the Agreement: Asset Manager.</u>

A: Based on the Hearing Examiner's report recommending approval of the Agreement the Company has proceeded to begin preparation of a list of assets, and to develop a work plan to accomplish provision C of the Agreement.

18. Q: <u>Please provide an update on Provision D of the Agreement: Pipeline Penalties.</u>

A: The Company made the assumption in calculating the proposed GCR rate included in this filing, that $34,075 (50 % of the January 2007 penalty) has been removed from GCR expenses per provision D of the Agreement. The Company is prepared to make this adjustment upon receipt of a Commission order approving Provision D.

19. Q: **<u>Did the Company incur any Pipeline penalties during the period June 2008 through July 2009?</u>**

A: The Company has not incurred any Pipeline penalties during the period June 2008 through July 2009.

20. Q: **<u>Please provide an update on Provision E of the Agreement: LNG Facility As It Relates to System Capacity.</u>**

A. Based on the Hearing Examiner's report recommending approval of the Agreement the Company formulated a request (statement of work) for a third party review and provided the draft to the Commission Staff and Public Advocate for review. The statement of work was modified based on feedback from the Parties and is attached as PLP-3. CH- IV International and Specialty Technical Consultants, Inc have been provided the statement of work. The Company is proceeding to work with the Consultants to develop and execute a work schedule based on this statement of work.

21. Q: **<u>Has the required Study been completed and included in the Company's pre-filed testimony ?</u>**

A: The Company, Commission Staff and Public Advocate agreed in July 2009 that it was appropriate for the Company to initiate the study, in advance of receiving a Commission ruling in Docket 08-266F. The Company chose Consultants familiar with certain aspects of the LNG plant in an effort to complete the study promptly. However even with these mutual efforts it is has been physically impossible to complete such a technical study by the time of this filing. The Company will continue to update the Parties on the progress.

22. Q: **Please provide an update on Provision G., Margin Sharing and Formula for Off-System Sales and Capacity Release.**

A. The Company is prepared to modify its accounting, upon receipt of a Commission order increasing the margin sharing threshold from $1.7M to $3.0M applicable to the tracking period beginning June 1, 2009. All calculations related to the proposed GCR in this filing assume the threshold to be $3M as evidenced in Mr. McGinnis testimony Exhibits CRM-2.

23. Q: **Does this conclude your testimony?**

A: Yes, it does.

GCR + ESR Sales Forecast 09-10

A	B	C	D	E	F	G	H	I
	30 Yr Average HDDs	Firm Sales						
	all in mcf	RES	RSH	GL	GG	MVG	LVG	Total
	Case v3r1	Regulatory Filings Case -- Weather Adjusted Sales Forecast						
1	Nov-09	19,584	558,158	20	328,041	33,631	7,266	946,699
2	Dec-09	32,761	1,076,803	20	545,646	57,547	20,038	1,732,815
3	Jan-10	32,121	1,331,141	20	728,930	70,868	28,246	2,191,325
4	Feb-10	32,666	1,552,519	20	743,845	73,939	32,390	2,435,379
5	Mar-10	31,352	1,351,027	20	654,013	66,722	26,481	2,129,614
6	Apr-10	25,133	781,246	20	441,370	43,027	22,658	1,313,454
7	May-10	16,771	352,903	20	248,643	25,167	13,713	657,217
8	Jun-10	13,270	186,606	20	170,957	15,775	3,718	390,345
9	Jul-10	10,457	133,708	20	149,016	14,173	4,572	311,946
10	Aug-10	9,612	120,454	20	132,138	13,617	5,006	280,846
11	Sep-10	10,394	130,478	20	144,814	11,906	4,618	302,229
12	Oct-10	11,248	169,523	20	201,090	18,273	3,320	403,473
13	*Total*	245,370	7,744,565	234	4,488,503	444,645	172,026	13,095,343
		Comparison to August 2008 GCR & ESR forecast of 07-08 GCR period :						
17	Total 08-09	276,238	8,452,579	252	4,565,442	706,665	382,229	14,383,405
18	Change	(30,867)	(708,014)	(18)	(76,939)	(262,020)	(210,203)	(1,288,062)
19	%Change	*-11.2%*	*-8.4%*	*-7.1%*	*-1.7%*	*-37.1%*	*-55.0%*	*-8.96%*

GCR + ESR Sales Forecast 09-10

A	B	K	L	M	N	P
	30 Yr Average HDDs	Firm Transportation				Firm Throughput
	all in mcf	GVFT	MVFT	LVFT	Total	
	Case v3r1	Regulatory Filings Case -- Weather Adjusted Sales Forecast				
1	Nov-09	29,783	96,551	312,732	439,066	1,385,765
2	Dec-09	42,261	118,473	338,865	499,599	2,232,414
3	Jan-10	50,601	142,970	376,665	570,236	2,761,561
4	Feb-10	39,719	113,953	331,229	484,901	2,920,280
5	Mar-10	38,562	105,771	314,685	459,018	2,588,632
6	Apr-10	26,222	78,309	270,251	374,782	1,688,236
7	May-10	15,224	63,364	269,258	347,846	1,005,063
8	Jun-10	12,082	55,079	255,195	322,356	712,701
9	Jul-10	11,428	56,903	315,663	383,994	695,940
10	Aug-10	11,287	56,670	332,953	400,910	681,756
11	Sep-10	11,767	61,684	307,465	380,916	683,145
12	Oct-10	18,257	80,043	324,128	422,428	825,901
13	*Total*	307,193	1,029,770	3,749,089	5,086,052	18,181,395
		Comparison to August 2008 GCR & ESR forecast of 07-08 GCR period:				
17	Total 08-09	155,568	922,396	5,210,971	6,288,935	20,672,340
18	Change	151,625	107,374	(1,461,882)	(1,202,883)	(2,490,945)
19	%Change	*97.5%*	*11.6%*	*-28.1%*	*-19.1%*	*-12.0%*

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF	)	
DELMARVA POWER & LIGHT COMPANY	)	
FOR APPROVAL OF MODIFICATION	)	PSC DOCKET NO. 08-266F
TO ITS GAS COST RATES	)	
(FILED AUGUST 29, 2008)	)	

PROPOSED SETTLEMENT

On this day, May 27, 2009, Delmarva Power & Light Company ("Delmarva" or the "Company"), the Delaware Public Service Commission Staff (the "Staff"), and the Public Advocate ("Public Advocate"), all of whom together are the "Parties" or "Settling Parties," hereby propose a complete settlement of all issues that were or could have been raised in this proceeding as follows:

I. INTRODUCTION AND PROCEDURAL BACKGROUND

On August 28, 2008, Delmarva filed an application (the "Application") with the Delaware Public Service Commission (the "Commission") to modify its Gas Cost Rate ("GCR") factors, effective on and after November 1, 2008, with proration, and with such revised factors to continue in effect until October 31, 2009. The Application seeks to change Delmarva's GCR in the following manner:

	Present		Proposed	
Rate Schedules	GCR Demand Charge	GCR Commodity Charge	GCR Demand Charge	GCR Commodity Charge
RG, GG and GL	N/A	96.517¢/ccf	N/A	117.560¢/ccf
Non-electing MVG	$10.20/Mcf of Billing MDQ	$8.2710/Mcf	$8.5538/Mcf of Billing MDQ	$10.5303/Mcf
Electing MVG and LVG	$10.2/MCf of Billing MDQ	Varies	$8.5538/Mcf of Billing MDQ	Varies
Standby Service	$10.2/Mcf of Standby MDQ	N/A	$8.5538/Mcf of Standby MDQ	NA

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In addition, the Application requested approval of the Company's proposal to reconcile and true-up actual versus estimated Weighted Average Commodity Cost of Gas ("WACCOG") assignments for sales under the Large Volume Gas service and for so-called "electing" customers taking service under the Medium Volume Gas service and for sales made under the Flexibly Prices Sales Service ("FPS").

On September 16, 2008, by Order No. 7444, the Commission permitted the proposed rates to go into effect on November 1, 2008, with proration on a temporary basis and subject to true-up and refund, pending evidentiary hearings and a final decision by the Commission.

The rates proposed in the Application result in a GCR increase of 14.8% for RG, GG and GL customers. Residential space heating customers using 120 ccf in a winter month would experience an increase of $25.25 or 14.8% in their total bill. Commercial and industrial customers served on Service Classifications GG and non-electing MVG would experience increases in their winter bills ranging from 8.7%-17.1% and 16.1%-22.3%, respectively, depending on load and usage characteristics.

On January 26, 2009, the Company filed a supplemental filing, requesting a reduction in its GCR commodity factors effective March 1, 2009. The Company's supplemental filing was necessitated by Delmarva's projection that its over-recovered balance would be 6.9% by October 31, 2009, exceeding the 4.5% threshold established by the Commission. Accordingly, the Company requested changes in its supplemental filing. According to this supplemental filing, the effect of the proposed commodity decrease on a residential space heating customer using 120 ccf per month is a decrease of $9.30 per month or 4.8%. Commercial and industrial customers served under Classifications GG and MVG experienced decreases in their total bills ranging from 2.1% to 3.0% and 5.6% to 6.5, respectively, depending upon usage and load characteristics. The changes are set forth below:

	Prior Demand Charge	Prior Commodity Charge	Proposed Demand Charge	Proposed Commodity Charge
RG,GG, and GL	N/A	$1.1756/Ccf	N/A	$1.09812Ccf
Non-electing MVG	$8.5538/Mcf Bidding MDQ	$10.5303/Mcf	$8.5538/MCF Billing MDQ	$9.7555/Mcf
Electing MVG And LVG	$8.5538/Mcf Billing MDQ	Varies	$8.5538/Mcf Billing MDQ	Varies
Standby Service	$8.5538/Mcf Billing MDQ	N/A	$8.5538/Mcf Billing MDQ	N/A

III. Settlement Provisions

A. The parties agree that subject to the commitments and agreements set forth below, approval of Delmarva's application, as filed, should be recommended to the Hearing Examiner and subsequently approved by the Commission.

B. Natural Gas Hedging Program

Staff has some concerns with both the annual percentage of GCR purchases at times hedged by Delmarva and the amount of discretion afforded to the Company in the current hedging program. Although Delmarva believes its hedging program as designed continues to be appropriate, it is not opposed to modifications of the program to reduce Delmarva's discretion in hedging its gas purchases.

After negotiations and consultations, the parties have agreed that Delmarva will revise its hedging program. Six gas hedging provisions or guidelines were approved by the Commission in Delaware PSC Docket No. 00–463F. The first two guidelines established 1) a minimum level of hedging and 2) an overall target level of hedging, as previously addressed above. Pursuant to

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this agreement, those two guidelines will be replaced by a fifty percent (50%) non-discretionary hedging program in which 50% of projected city gate requirements and storage injections are to be hedged on a pro rata basis (1/12th each month) over the 12-months preceding the month in which the physical gas is to be delivered to customers. Except in the event of extraordinary circumstances as set forth below, the hedging program set forth in this paragraph will be conducted without regard to anticipated price trends.

The parties acknowledge that the implementation of the new hedging program will take place over time due to pre-existing hedging positions which may, in some months, be outside the parameters of the new hedge program.

If, in the exercise of its business judgment, the Company believes there are extraordinary circumstances that may warrant varying from the hedging program agreed to herein, the Company will seek the agreement of Staff and Public Advocate to temporarily modify the hedge amounts from the fifty percent (50%) or 1/12th monthly requirements. Staff and Public Advocate will analyze the request and either agree or request its expedited consideration by the Commission.

The Company agrees to file its Quarterly Hedging Report within 30 days following the close of the quarter.

The parties agree that the 50% non-discretionary program agreed to herein is subject to alteration should it prove unsuccessful in future years.

Management of the Company's Gas Division will meet monthly with the individuals and/or entity conducting the hedging program to review ongoing results. In the section of the Company's prefiled testimony for the 2009-2010 GCR filing that reviews hedge results, the

Company will address commodity costs related to hedge purchases made in 2008 under the prior hedging program and the effect such purchases have on the 2009-2010 GCR.

C. Asset Management

All parties agree that the Company will inventory its gas assets and develop a Request For Proposal ("RFP") from several asset managers for the potential management of Delmarva's gas portfolio, as well as for alternative proposals to manage subsets of that portfolio as potential managers may define. The goal is to have the RFP completed so that any potential asset management agreement could be entered into no later than April 2010. It was also agreed that performing an RFP will not obligate Delmarva to enter into an asset management agreement if, after examining the results of the RFP, Delmarva determines that the best interests of its customers and, where appropriate, Delmarva, would be to have Delmarva and/or its service company continue asset management activities. Delmarva further agrees to begin formulating an RFP and to seek Staff and Public Advocate comments on the RFP documents.

D. Pipeline Penalties

The Company incurred a pipeline penalty of $68,150 for overtaking 3,326 Dth of FSS supply in January 2007. Staff raised the question as to why the Company had a capacity deficiency on a day that was not extremely cold. The Company explained that because it was unable to take the entire amount of gas nominated on TETCO pipeline due to lower than needed delivery pressure and it was necessary to take delivery of gas via the Columbia pipeline which had a higher delivery pressure at that time and, accordingly, requested that sales customers pay the penalty.

Although Delmarva does not believe it should be responsible for the cost absent any wrongdoing related to this, Staff and Public Advocate feel that customers should not be responsible either. Further, Staff, Public Advocate and Delmarva agree that the 50% sharing of the penalty applies only to this "penalty" without precedent and that, in the future, Delmarva will report penalties, in future GCR filings, to both Staff and Public Advocate, if and when, they are incurred.

E. LNG Facility As It Relates To System Capacity

The parties agree that an independent third party will conduct a review of the LNG facility related to its potential capacity and that such review should be completed prior to the Company's next GCR rate filing.

Delmarva agrees to perform the review and the other parties agree, that the results of any review will not obligate Delmarva to alter its operations or planning with respect to the LNG facility if, after examining the results of the review, Delmarva agrees that the best interests of customers and, where appropriate, Delmarva, would be to reject some or all of the recommendations arising out of the review. Delmarva agrees to begin formulating a request for a third party review as soon as reasonably possible and will seek review and comment from Staff and Public Advocate on the request for review.

F. Company Utilization of Storage

The parties agree that this is no longer a disputed issue.

G. Margin Sharing and Formula for Off-System Sales and Capacity Release

Beginning in 2001-2002, a margin sharing structure was created whereby the Company retained 20% of total gas sales in excess of $1.7 million in an effort to incentivize the Company to maximize sales and margin credits for the benefit of firm customers. Since ratepayers pay all capacity-related costs, it was believed that creating this program would result in net benefit to firm customers by increased sales.

Staff raised the issue as to whether the threshold of $1.7 million was appropriate given certain structural changes in the gas industry. Staff maintains that incentives should only be given for superior performance.

Delmarva believed that the change in the current margin sharing was not appropriate and that if such a change was made (an increase in the threshold), an increase in the amount of margin shared between ratepayers and the Company should be adjusted as well.

To resolve this issue, the parties have agreed that the margin sharing percentage should remain the same (80/20) and that the threshold should move from $1.7 million to $3 million. The parties believe that this is a reasonable compromise of this issue.

H. Additional Provisions

1. The provisions of this settlement are not severable.

2. This Settlement represents a compromise for the purposes of settlement and shall not be regarded as a precedent with respect to any ratemaking or any other principle in any future case. No Party to this settlement necessarily agrees or disagrees with the treatment of any particular item, any procedure followed, or the resolution of any particular issue in agreeing to this settlement other than as specified herein, except that the Parties agree that the resolution of the issues herein taken as a whole results in just and reasonable rates.

3. To the extent opinions or views were expressed or issues were raised in the pre-filed testimony that are not specifically addressed in the Settlement, no findings, recommendations, or positions with respect to such opinions, views or issues should be implied or inferred.

IN WITNESS WHEREOF, intending to bind themselves and their successors and assigns, the undersigned parties have caused this Proposed Settlement to be signed by their duly-authorized representatives.

Delaware Public Service Commission Staff

By:________________________

Delmarva Power & Light Company

By:________________________

Public Advocate

By:________________________

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Delmarva Power LNG Facility 2009 Review Statement of Work

"In the context of and in comparison to gas industry standards and practices:

1. Assess current state of Delmarva LNG Plant Vaporization System reliability and capacity,

2. Identify potential actions to increase reliability and/or capacity, and

3. Identify and analyze the impact and considerations associated with implementation of the potential improvements identified, including the costs vs. benefits of any such improvements.

The above review is being performed in compliance with the following agreement between Delmarva, the Delaware Public Service Commission and the Delaware Office of the Public Advocate. As such the Consultants should be available for separate discussions with the parties as requested.

' E. LNG Facility As It Relates To System Capacity

The parties agree that an independent third party will conduct a review of the LNG facility related to its potential capacity and that such review should be completed prior to the Company's next GCR rate filing.

Delmarva agrees to perform the review and the other parties agree, that the results of any review will not obligate Delmarva to alter its operations or planning with respect to the LNG facility if, after examining the results of the review, Delmarva agrees that the best interests of customers and, where appropriate, Delmarva, would be to reject some or all of the recommendations arising out of the review.

Delmarva agrees to begin formulating a request for a third party review as soon as reasonably possible and will seek review and comment from Staff and Public Advocate on the request for review.'"

W. THOMAS BACON JR

DELMARVA POWER & LIGHT COMPANY

TESTIMONY OF W. THOMAS BACON JR.

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

CONCERNING THE NOVEMBER 2008 THROUGH OCTOBER 2009

GAS COST RATE

PSC DOCKET NO. 09-

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1. Q: <u>Please state your name, occupation, and business address.</u>

A: My name is W. Thomas Bacon Jr. and I am employed by PHI Service Company as Director – Gas Supply & Regulatory Planning. My business address is P.O. Box 6066, 500 North Wakefield Drive, Newark, Delaware 19714.

2. Q: <u>Please briefly summarize your educational and professional background.</u>

A: I hold a Bachelor of Arts Degree in Sociology from Wittenberg University and a Masters of Science Degree in Agricultural Economics from The Ohio State University.

I have been employed by PHI Service Company or its affiliates, including Delmarva Power & Light Company, since June 1994 serving in a variety of gas supply planning & procurement, strategic planning, rate and regulatory functions.

Prior to this, I was employed for over seven years by Chesapeake Utilities Corporation and its subsidiary, Eastern Shore Natural Gas Company in several areas including gas supply, and rate and regulatory affairs.

I began my utility-related career with the Ohio Department of Energy ("ODOE"). At the ODOE, and subsequently with other state agencies including the Public Utilities Commission of Ohio, my primary duties involved evaluating the reasonableness and prudence of gas and electric utility long-term forecasts of supply and demand.

3. Q: **<u>Have you previously testified before a regulatory commission?</u>**

A: Yes. I have testified before state utility commissions in Florida, Maryland and Delaware on a number of gas utility cost of service, rate and rate design, gas supply and regulatory policy matters. I have also submitted pre-filed direct testimony before the Public Utilities Commission of Ohio and the Federal Energy Regulatory Commission ("FERC") primarily dealing with interstate pipeline cost of service, rate design and gas cost recovery mechanisms.

4. Q: **<u>What is the purpose of your testimony in this proceeding?</u>**

A: I am testifying on behalf of Delmarva Power & Light Company, ("Company") supporting the Gas Cost Rate ("GCR") proposed to be effective from November 1, 2009 through October 31, 2010. My testimony presents the development of the total estimated gas supply costs for the period, consisting of all gas commodity costs; interstate pipeline transportation demand costs, storage demand and capacity costs, storage withdrawal/injection costs, variable transportation commodity, fuel and capacity release and off-system sales revenue credits. As part of the Natural Gas Hedging Program Update, my testimony also addresses the provision in the Proposed Settlement Agreement executed by the parties in last year's GCR proceeding, PSC

Docket No. 08-266F, regarding the impact on the 2009-2010 GCR from hedges entered into during the calendar year 2008.

In addition, the Company is proposing a change to its balancing fee from $0.3368 per MCF to $0.4242 per MCF of imbalance volumes.

My testimony is organized as follows:

1. Interstate Pipeline Transportation and Storage Services,
2. Firm Natural Gas Purchase Requirements,
3. Natural Gas Commodity Costs and Prices,
4. Natural Gas Hedging Program Annual Update, and
5. Capacity Release and Off-System Sales activity.

<u>Interstate Pipeline Transportation and Storage Services</u>

5. Q: <u>Please outline the Company's firm interstate pipeline and storage capacity and supplemental supply portfolio available for this upcoming GCR period.</u>

A: Schedule WTB-1 - Portfolio of Firm Transportation & Storage Services as of November 1, 2009 - summarizes the firm transportation and firm storage services presently under contract that have primary delivery points to Delmarva's interstate pipeline interconnects. Based upon these upstream contracts and the planned-for design day vaporization of 25,000 Mcf from the Company's LNG facility, the Company has 193,385 Mcf of peak or design day supply deliverability available to meet firm sales customer requirements.

6. Q: <u>What are the major differences between this year's projected transportation and storage demand costs versus those contained in last year's annual GCR filing?</u>

A: Annual projected fixed costs related to all of the Company's transportation and storage services are summarized in Schedule WTB-2. Schedule WTB-2 also compares the projected 2009-10 costs with the estimates included in last year's GCR application. Overall, compared to last year's application, fixed gas costs are projected to increase by $2.6 million per year, or slightly more than 10%. The change in fixed costs is attributable primarily to (a) full annualization of Transco Sentinel capacity, (b) addition of Eastern Shore capacity and E-3 Project Surcharge, and a (c) correction of Transco PS-3 billing determinants.

All pipelines rates and charges included are the respective pipelines' most currently effective rates.

7. Q: <u>Is the Company proposing to increase the Transportation Balancing Fee assessed on the imbalance volumes of all transportation service customers?</u>

A: Yes. The Company is proposing to increase the Transportation Balancing Fee from $0.3368 per MCF to $0.4242 per MCF. Schedule WTB-3 contains the projected costs of those services the Company relies on to provide all customers with no-notice swing capability and reliable system pressures year round but especially important during the winter months. The Company estimates it will pay approximately $8.1 million per year in fixed costs for pipeline no-notice storage and for firm transportation services that are required to a) manage the daily load swings and b) provide adequate delivery pressure for both its firm sales as well as transportation customers. The Transportation Balancing Fee is derived by taking these projected costs and dividing by the projections of all firm sales and transportation throughput.

There has been no change in methodology in the calculation of the proposed balancing fee. The increase in the proposed Transportation Balancing Fee is due to (a) increases in the fixed cost of the upstream services shown on Schedule WTB-3 and (b) a decrease in overall throughput.

8. Q: <u>Has the Company included any forecast of interstate pipeline bill credits or refunds in this year's GCR Application?</u>

A: No. The Company does not expect to receive any material pipeline refunds during the November 2009 – October 2010 GCR period.

<u>Development of Firm Natural Gas Purchase Requirements</u>

9. Q: <u>Please describe the development of the system's gas requirements forecast?</u>

A: Firm sendout is based upon (a) a billing month forecast of firm sales provided by Company Witness Phillips, adjusted for (b) a 2.00% percentage factor for losses and unaccounted-for-gas and (c) a cycle billing effect. In this Application, non-firm sendout is assumed to be zero based upon the Company's recent experience of no sales under its Flexibly Priced Citygate Sales Service ("FPS"). Schedule WTB-4 presents the firm sales and unaccounted-for/cycle billing estimates for the August 2009 to October 2010 period.

10. Q: <u>How are the projected demand, supply and price forecasts integrated?</u>

A: For each month of the forecast period, sources and disposition of supply are matched, taking into consideration customer demand, storage inventories, contractual limitations and economics. The gas procurement process takes into account reliability of supply, operational considerations and contract obligations yet is structured to acquire gas supplies at the lowest reasonable cost. This process is consistent with the objectives as stated in the Company's 5-Year Strategic Gas Supply Plan. Schedule WTB-5 summarizes the Company's projected gas demand, supply and supply prices for the forecast period, August 2009 through October 2010.

Natural Gas Commodity Costs and Prices

11. Q: Please explain the major causes for the Company's projected deferred fuel balance of approximately $3.256 million under-recovered for October 31, 2009.

A: Table 1 below contains a summary of the reconciling items that comprise this projected variance. Overall, the variance can be explained by (a)) higher unit commodity costs, (b) more purchases than sales, net of gas costs, and (c) higher demand costs offset by (a) higher capacity release and off-system sales margins, (b) reforecast for August-October 2009 compared to what was filed last year in the 2008-09 GCR Application for the same months and the (c) net reduction of revenues and costs inherent in the January 2009 Interim GCR rate filing.

Table 1. Reconciliation of Projected 10/31/09 Under-Recovery

	Description of Variance	(Over-) or Under Recovery
1	Net Reduction of Revenues & Cost Inherent in Interim Filing	$ (3,422,038)
2	More Purchases than Sales & Lower Unit Revenue, Net of Gas Costs	$ 2,534,982
3	Higher Capacity Release & OSS Margins	$ (573,821)
4	Higher Fixed Demand Costs	$ 1,264,804
5	Higher Unit Commodity Costs	$ 6,963,171
6	Updated Forecast for August-October 2009	$ (3,510,829)
7	Total Estimated Underrecovery at October 31, 2009	$ 3,256,268

12 Q: <u>Can you summarize the projected natural gas commodity costs for the November 2009 to October 2010 determination period contained in the Company's annual GCR application?</u>

A: Yes. The Company's anticipated natural gas commodity purchases for the November 2009 to October 2010 GCR determination period consists of three major components summarized in Table 2 below: 1) natural gas withdrawn from storage, 2) gas purchased that is hedged at the time the cost forecast was prepared, and 3) "spot" gas, or gas purchased that is not hedged at the time the cost forecast was prepared. In the Company's 2009-10 GCR filing, storage withdrawals, hedged purchases, and spot purchases are projected to make up about 23%, 62% and 15% respectively of the estimated commodity requirements for the November 2009 to October 2010 period.

The Company's estimated average storage withdrawal costs are again expected to be lower that the current average hedge cost or projected spot purchases due to the drop in market prices this summer and storage hedges in place.

The total estimated commodity cost of $101,714,877 found on line 6 in Table 2 above can also be found on Schedule WTB-5, page 18, at line No. 298.

<u>Table 2. Summary of 2009-10 Projected Commodity Costs</u>

	(1)	(2)	(3)	(4)	(5)
	Source of Supply	Percent	Supply (Mcf)	$/Mcf	Commodity Cost
1	Storage Withdrawals	23%	3,002,453	$ 7.90	23,732,852
2	Hedged Purchases	62%	8,298,842	$ 7.77	64,472,484
3	Spot Purchases	15%	2,042,937	$ 5.27	10,765,055
4	Total Purchases	100%	13,344,232	$ 7.42	98,970,391
5	Variable Costs & Pipeline Fuel			$ 0.21	2,744,486
6	Total Commodity Costs				101,714,877

13. Q: **<u>What source did the Company select for development of its price forecast for spot purchases?</u>**

A: In its 2009-10 GCR filing, the Company used the NYMEX gas futures closing prices on July 31, 2009 as its spot (wholesale) gas price. This wholesale price forecast is applicable to estimated purchases after storage withdrawals and hedged purchases were first considered.

14. Q: **<u>Why did the Company choose NYMEX futures prices as the most appropriate to use for its spot price forecast?</u>**

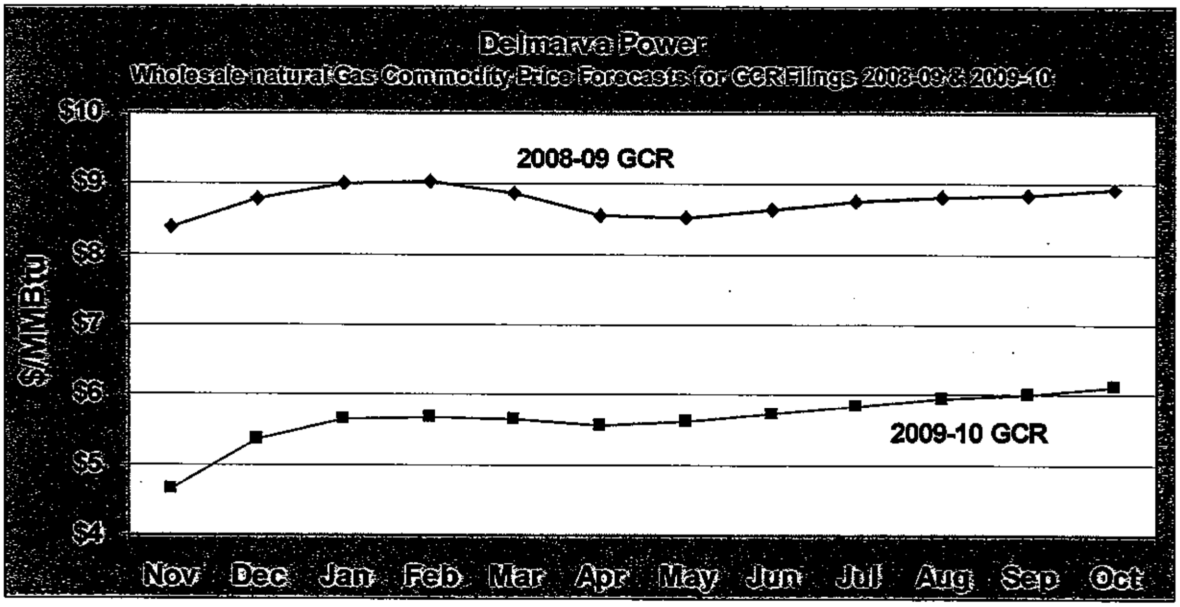
A: Based upon a prior settlement agreement, the Company relies upon NYMEX natural gas futures prices as a primary tool in establishing its wholesale gas commodity forecast used in the proposed GCR each year. Specifically, the Company uses NYMEX gas futures prices based upon a single day's close or an average of two or more days of closing prices selected from actual gas futures closing prices observed between July 20 and August 20 each year. The Company does have the discretion to use another basis for its wholesale gas commodity forecast if the Company believes it would result in a more accurate GCR forecast.

In preparing this application, the Company examined a number of resources and inputs and concluded that the NYMEX natural gas futures closing prices on July 31, 2009 were reasonable for use as the wholesale natural gas price forecast and that using a different methodology was not likely to provide a more accurate GCR forecast. Even though the Company has discretion under appropriate circumstances to deviate from the use of NYMEX natural gas futures prices as its wholesale gas price forecast, there are no compelling reasons to do so in preparation of the 2009-10 GCR cost forecast.

15. Q: <u>How does the 2009-10 gas commodity price forecast compare to the 2008-09 gas commodity price forecast?</u>

A: Overall, 2009-10 wholesale gas commodity costs are projected to be on average about $5.65 per MMBtu or about 35% lower in this filing compared to 2008-09 filing (see Figure 1 below).

<u>Figure 1. Comparison of Delmarva's Wholesale Natural Gas Price Forecasts</u>



<u>Natural Gas Hedging Program Annual Update</u>

16. Q: <u>How does the goal of the Company gas hedging program relate to its overall objective of the Company's overall natural gas planning and procurement strategy?</u>

A: The objective of the Gas Hedging Program is to reduce gas commodity price volatility while limiting the firm sales customers' exposure to increases in the market price of gas. The intent of the Program is to implement a hedging strategy to reduce commodity price uncertainty, but not necessarily provide the absolute lowest possible commodity price.

The overall objective of the Company's Gas Supply Planning & Procurement Strategy is to provide reliable natural gas supply and service to core residential, commercial and industrial customers at the lowest reasonable cost. To ensure reliability, the Company secures by long-term contract the needed pipeline and storage services to serve its core customers' firm requirements.

The Gas Hedging Program has been focused to reduce commodity price volatility. The Company's overall Gas Supply Planning & Procurement Strategy is to ensure reliability at a reasonable cost.

17. Q: <u>Is the Company willing to discuss modifications to these two objectives?</u>

A: Yes it is. The Proposed Settlement in last year's GCR proceeding contained changes to the Company's hedging program, therefore, revisiting the Gas Hedging Program objective seems to make sense. The Company is also willing to discuss changes to the Company's objectives regarding Gas Supply Planning & Procurement.

18. Q: <u>What is the primary method used to measure how well the Gas Hedging Program meets its goal?</u>

A: In 2004, a metric was introduced to measure how well the Hedge Program meets its volatility related goal by comparing the standard and average deviations of the 1) the Company's average monthly hedge cost ("Hedge Wacog"), and 2) the weighted average delivered commodity cost of gas ("WACCOG") with 3) the monthly NYMEX natural gas contract last day settle price. Schedule WTB- 6 summarizes these measures for each GCR period since November 2005 and for the period November 2008 to June 2009. Overall, standard and average deviations for both the Hedge Wacog and the WACCOG track below that of the NYMEX natural gas contract settle prices. Therefore, it appears that the Company's hedging program is meeting its objective to minimize the effect of gas price volatility on customers.

19. Q: <u>Are there other ways the Hedge Program results can be evaluated?</u>

A: Yes. As discussed among the parties in last year's GCR proceeding, average hedge costs could be compared to average market prices prevailing over a twelve to eighteen month period prior to a given month of use. It can be expected that in any given period, average hedge costs may be higher than average market prices. However, it was reasonable to expect that, over time, average hedge costs should approximate average market prices. Schedule WTB- 7 compares the Company's average hedge cost and its overall average delivered commodity cost (WACCOG) with the prior 12- and 18-Month averages of the daily NYMEX gas futures closing prices. An estimate for pipeline fuel and variable costs were removed from the (delivered) WACCOG to make it comparable to both the Hedge Wacog and the futures prices, which are both relative to the Henry Hub, Louisiana. For the first three GCR periods shown on Schedule WTB-7, the Company's hedge wacog and WACCOG compares very favorably to the prior 12- and 18-month gas futures prices. For the Nov08-June09 period, the Company's WACCOG was approximately the same as the NYMEX gas futures prices while the average hedge cost was $0.26 per MMBtu or 2.95% above the NYMEX gas futures prices.

20. Q: <u>Have you made a comparison of the Company's gas cost rate with the comparable or equivalent gas cost rates of other gas utilities?</u>

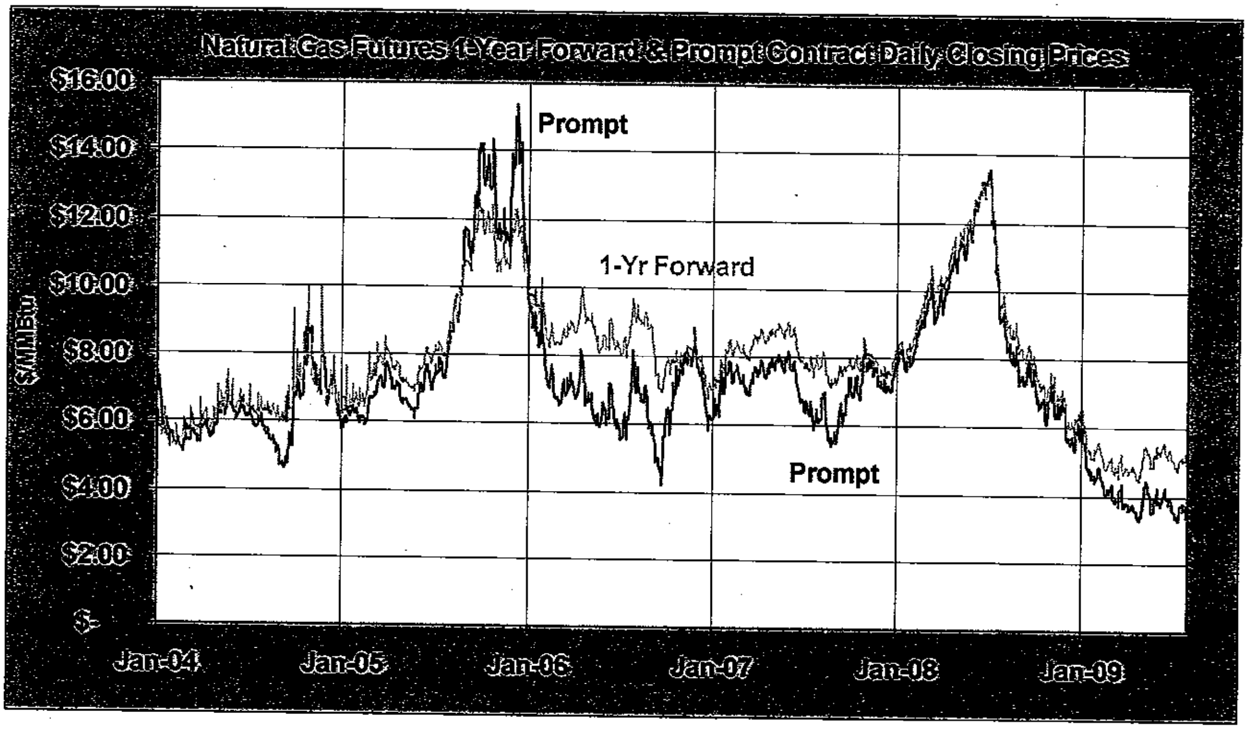
A: Yes. Two comparisons have been prepared. The results indicate that over time the Company compares reasonably well with the benchmark group over two different time periods; the last 2 years and the last 5 years respectively. Schedule WTB-8 compares the Company's weighted average residential space heating gas supply cost rates to the equivalent rate for selected benchmark gas companies in New Jersey, Pennsylvania and Maryland for 2-Years and 5-Years ended July 2009. The weighted average is calculated using a Delmarva Power residential space heating monthly load profile.

For the 2-Year period ended July 2009, the Company ranks 4th out of the 10 benchmark LDCs. For the 5-Year period ended July 2009, the Company ranks 3rd out of 10 benchmark LDCs.

The second graph on Schedule WTB-8 shows the gas supply cost rates in effect during the month of July 2009. In this comparison, the Company ranks 8th out of 10 benchmark LDCs. This is directly related to differences in the frequency of when rates change; monthly, quarterly or annually. BG&E and WGL, the two Maryland LDCs, have <u>monthly</u> gas supply cost rates which more closely tracks the downward movements of the wholesale gas commodity market price as shown in Figure 2 below. The Pennsylvania LDCs, PECO, PGW, PPL, PG Energy and UGI, change gas supply cost rates on a <u>quarterly</u> basis. New Jersey and Delaware have <u>annual</u> gas cost rate mechanisms with rate changes taking place in the fall each year. Given the market price movements shown in Figure 2, it is not too surprising that the two Maryland

LDCs have generally lowest rates while the Pennsylvania LDCs are above Maryland and New Jersey and Delaware are above Pennsylvania rates.

Figure 2. Gas Futures 1-Year Forward & Prompt Contract Daily Closing Prices



21. Q: Did the Proposed Settlement in last year's GCR proceeding PSC Docket No. 08-266F include a requirement on the part of the Company to address hedge transactions made in 2008?

A: Yes. As part of the Proposed Settlement the Parties entered into in last year's GCR proceeding, the Company agreed as part of its 2009-2010 GCR prefiled testimony to "address commodity costs related to hedge purchases made in 2008 under the hedging program and the effect such purchases have on the 2009-2010 GCR."

22. Q: How do you propose to specifically comply with this portion of the Proposed Settlement Agreement?

A: First, it may be helpful to have a general understanding of how the Company implements the Gas Hedging Program. Second, some general background relative to the wholesale gas price environment over the applicable time period is provided. Third, the 2008 Hedges are presented and categorized according to reasons the Company entered into the hedge. Finally, the effect of the 2008 Hedges on the 2009-2010 will be quantified.

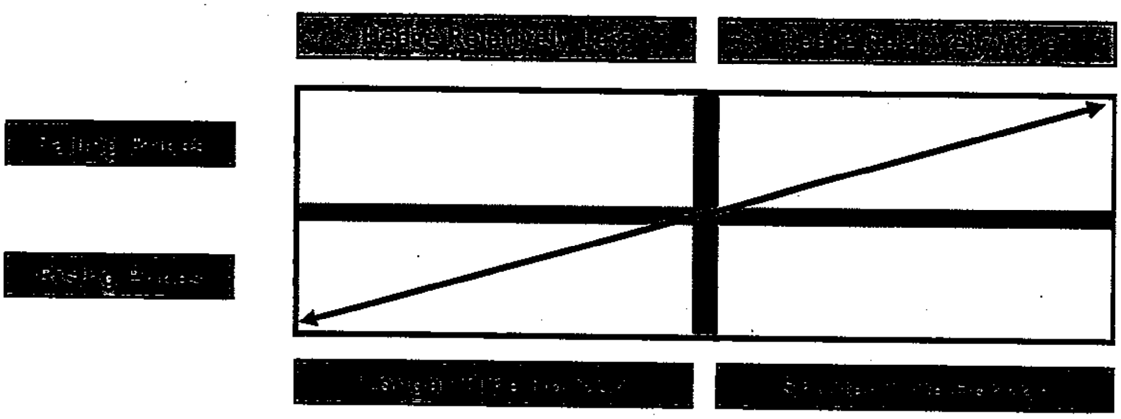
23. Q: Can you please describe how the Company implements it current Gas Hedging Program?

A: Yes. The following two Gas Hedging Program guidelines (approved by the Commission in PSC Docket No. 00-463F) provide guidance relative to minimum and target levels of hedging. The first establishes a minimum level of hedging, expressed as a percentage of monthly purchases. At a point 18, 12 and 6 months prior to natural gas being purchased, 10%, 20% and 30%, respectively, of estimated purchase requirements should be hedged. The second guideline establishes a target level of hedging of up to 70% of annual GCR purchases. However, this target is not intended to be a maximum, is subject to the business judgment of the Company and assumes a normal balance between supply and demand in the wholesale gas market. The burden is on the Company to explain any deviations from these guidelines.

24. Q: The above two hedging guidelines provide guidance on hedge quantity, not when to hedge. How does the Company determine when it is a reasonable time to hedge?

A: Schedule WTB-9 lists a number of considerations that can influence its decision when to hedge. Importantly, the Company attempts to layer in small quantities of hedges over time consistent with minimum hedge percentage guideline. In addition, the Company uses a concept called hedge identification and proportioning to help it identify a reasonable time to hedge regardless of current market price movements or expectations about the direction of future market prices. For example, as prices decline, the Program attempts to lock in a greater percentage of total volumes. Conversely, if prices rise, a relatively lower amount of total volumes could be hedged. When the time horizon until gas is purchased and delivered to customers is relatively long, relatively less amounts of gas would be hedged.

Figure 3. Hedge Identification and Proportioning Guideline



As you get close to the time when gas is purchased and delivered to customers, relatively larger amounts of gas could be hedged. This concept is graphically presented in Figure 3 above. Implementation of this concept is discussed below and illustrated in Figure 5.

25. Q: <u>Can you describe the natural gas market price environment that existed during 2008?</u>

A: The last 24 months has seen unprecedented, extraordinary shifts in market direction. Figure 2 above tracks the average 1-Year Forward and Daily Closing Prices for natural gas futures prices as traded on the New York Mercantile Exchange ("NYMEX") since January 2004 through July 2008. The extreme run-up in natural gas futures prices that began in early September 2007 and ending 10 months later in early July 2008 was not foreseen. During this time period, natural gas futures prices rose over 141% from $5.63 to $13.58 per MMBtu. The even more extreme price decline that began in July 2008 was also not predicted. Moreover, recessions in the U.S. and globally have extended this price decline well beyond what the gas market has ever experienced. Through July 31, 2009, the natural gas futures daily closing price fell to as low as $3.26 per MMBtu, a drop of $10.32 per MMBtu, or 76%.

26. Q: <u>Can you please summarize the hedge transactions the Company entered into during 2008?</u>

A: Schedule WTB-10 contains a summary of all hedge purchases made in 2008 including date of transaction, type of transaction, price, daily quantity and hedge term. A total of 51 transactions were entered into during 2008. Seven of the transactions hedged the Company's estimated injections into storage, while the remaining 44 were hedges of estimated purchases that were directly delivered to customers.

27. Q: <u>Can you summarize the reasons why the Company entered into the 2008 hedges as found on Schedule WTB - 10?</u>

A: Yes. In general, the 2008 hedge transactions listed in Schedule WTB-10 were entered into mainly for one of three reasons: a) to comply with the minimum hedge percentage guideline, b) as a result of decreases in market prices, and c) to reduce inside-the-month commodity price risk. Figure 4 below provides a summary of the 2008 hedges transactions by number, volume and percent.

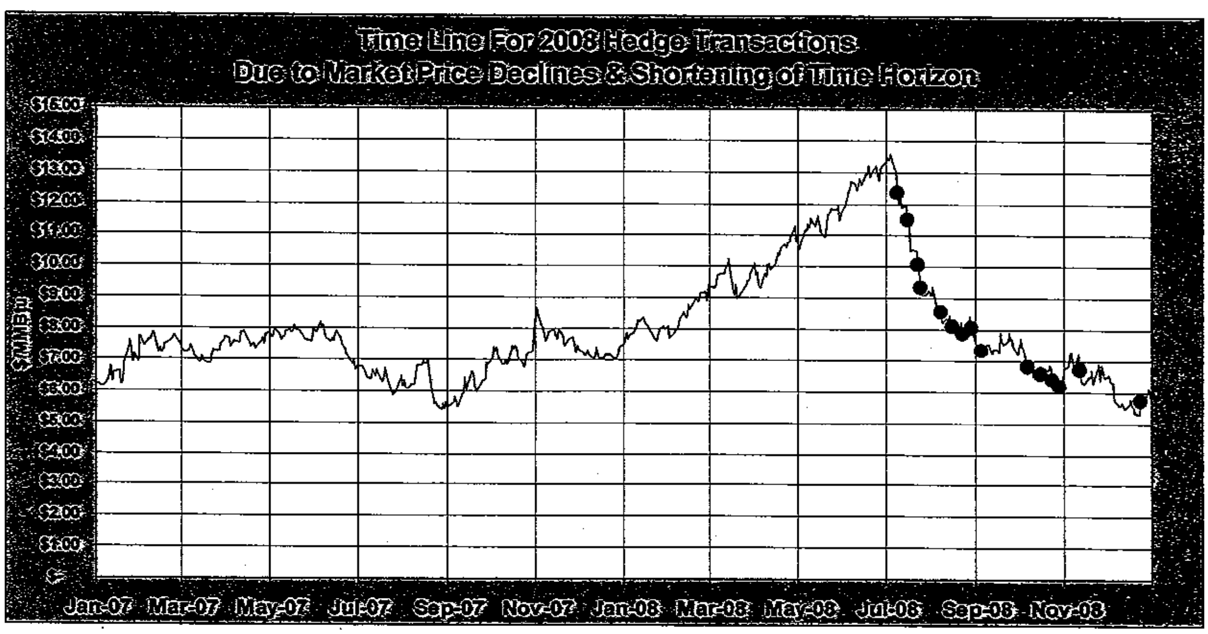
Figure 4. Summary of 2008 Hedge Transactions

Description of 2008 Hedge	No. of Transactions	Hedge Volume	Percent
Comply w/ Minimum Hedge Guideline	15	4,542,500	30%
Decrease in Market Price	27	10,022,500	66%
Reduce inside-the-month price risk	9	587,500	4%
Total 2008 Hedges	51	15,152,500	100%

There were 15 hedge transactions during 2008 that were made in order to comply with the Hedge Program's minimum hedge percentage guidelines. These transactions took place between February 21, 2008 and July 17, 2008.

Between July 9, 2008 and December 23, 2008, the Company entered into 27 hedge transactions as a result of a) declines in the natural gas futures market price and b) shortening of the time horizon until gas is purchased and delivered to customers. Figure 5 below depicts the time line of when these hedge transactions were executed. There are less than 27 bullets in Figure 5 because on some days more than one hedge transaction was completed.

Figure 5. Transactions Executed Due to Price Declines & Shortening of Time Horizon



28. Q: <u>Please elaborate why the Company made the decision to reduce the risk of inside the month price volatility by entering into 9 swing swaps during 2008.</u>

A: In a given month, the Company can purchase gas at NYMEX last day settle plus basis, a first of the month index price, or it can buy gas inside the month on a daily basis if it believes prices may fall from the first of the month levels. Once the month begins and if the Company has not locked the price of all of its estimated monthly purchases, it can purchase a swing swap when a) the next day spot market price for gas has declined more than expected since the beginning of the month, or b) there is a risk of an increase in spot prices at some point during the remainder of the month [e.g., due to a new weather forecast being published]. A swing swap is where the Company financially fixes the price it pays for gas for the remaining days of the month. In 2008, the Company entered into 9 swing swaps during the months of May through September 2008. For the May-July period, there was a significant drop in spot market prices as compared to that month's Last Day Settle price. In August and September 2008, there was a more modest decline between spot and Last Day Settle prices, but there also existed threats of hurricanes that could cause disruption of gas and oil production resulting in price spikes. Figure 6 shows, for the months of May to September 2008, the Last Day Settle Price, the Average Price of the Swing Swap and the difference between the two.

<u>Figure 6. Last Day Settle Price Compared to Swing Swap Average Strike Price</u>

	LDS Price	Average Strike Price	Change
May-08	$ 11.28	$ 10.71	$ 0.57
Jun-08	$ 11.92	$ 11.35	$ 0.57
Jul-08	$ 13.11	$ 11.63	$ 1.48
Aug-08	$ 9.22	$ 8.82	$ 0.39
Sep-08	$ 8.39	$ 8.18	$ 0.21

29. Q: <u>Can you quantify the volume and average cost of the 2008 hedges?</u>

A: Figure 7 below provides the 2008 Hedges by the period in which they settle and the associated average cost. The costs of the 2008 Hedges that settled during

<u>Figure 7. 2008 Hedges Summarized by Settle Date and Average Cost</u>

	2008 Hedges	April'08 to July'09	Aug'09 to Oct'10	Nov'10 Forward
Total Hedges	15,152,500	8,595,000	5,187,500	1,370,000
Average Cost	$ 9.44	$ 9.75	$ 9.34	$ 7.91

April 2008 through July 2009 have been realized and are reflected in the Company's recovery position as of July 2009 (see Schedule CRM-6 of Company Witness McGinnis). The impact of any 2008 hedge that has already settled; i.e., for the period April 2008 through July 2008 is reflected in the 9 months actual and 3 months estimated costs for the 12 months ending October 31, 2009. There are 9,060,000 MMBtu of these at an average cost of $9.74 per MMBtu.

The 2008 hedge costs for August 2009 through October 2010 are included as part of the Company's gas commodity cost forecast along with the cost of storage withdrawals, spot gas purchases and other hedges. There are 5,187,500 MMBtu of 2008 hedges from August 2009 through October 2010 that have an average hedge cost of $9.34 per MMBtu.

The 2009-2010 GCR has a determination period of November 2009 through October 2010; therefore any hedge for a month beginning with November 2010 and beyond will not have any effect on the 2009-2010 GCR. Of the 2008 Hedges, 1,370,000 MMBtu at an average cost of $7.91 per MMBtu fall in this category and are excluded.

30. Q: <u>What is the impact that the 2008 hedge purchases had on the 2009-2010 GCR?</u>

A: Overall, the impact hedge purchases made in calendar year 2008 on the 2009-2010 was not surprising given the market price movements that occurred since January 2008. While these specific 2008 hedged positions have resulted in costs that are higher than they would have been had the Company not hedged its firm supply requirements, the Company's actions were consistent with the Gas Hedging Plan.

As shown in Figure 3 above, 30% of the 2008 hedges were to meet the Hedge Program's minimum hedge requirement. 66% of the hedge transactions were entered into over the last 6 months of 2008 as the market price declined. Figure 3 depicts the declining "stair-step" fashion execution of these hedges as the market price fell during the last half of 2008. This is consistent with long-standing practice of layering in hedges as market prices decline and the time horizon (until natural gas is purchased and delivered to customers) becomes shorter.

Finally, 4% of the hedge transactions were swing swaps done in the months of May, June, August and September 2008 to lock in prices at significant decreases off of Last Day Settle Prices. The 2008 hedges did not result in "excess" hedges. For the period January 2008 through July 2009, the actual percentage of estimated purchases that were hedged was 68%.

<u>Capacity Release and Off-System Sales Activity</u>

31. Q: <u>Please summarize the capacity release and off-system sales activity as found in the forecast period.</u>

A: For the forecasted GCR period, the Company estimates it will achieve $9.4 million in gross margins from off-system sales and capacity release transactions during the November 2009 to October 2010 period as shown in Figure 8 below.

The $9.4 million in forecasted gross margin is $700,000 above the $8.7 actual gross margin achieved for the 12 M.E. July 2009. The increase in the forecast compared to actual is attributable to an expectation that unit margins from off-system sales will be higher as a result of higher market value for transportation capacity.

Figure 8. Forecast of Capacity Release & Off-System Sales Gross Margin

Delmarva Power
Forecast of Total Capacity Release & OSS Gross Margin

	Total	Cap Rel	OSS
Nov-09	$ 850,000	$ 550,000	$ 300,000
Dec-09	$ 850,000	$ 550,000	$ 300,000
Jan-10	$ 850,000	$ 550,000	$ 300,000
Feb-10	$ 850,000	$ 550,000	$ 300,000
Mar-10	$ 850,000	$ 550,000	$ 300,000
Apr-10	$ 800,000	$ 550,000	$ 250,000
May-10	$ 750,000	$ 550,000	$ 200,000
Jun-10	$ 700,000	$ 550,000	$ 150,000
Jul-10	$ 700,000	$ 550,000	$ 150,000
Aug-10	$ 700,000	$ 550,000	$ 150,000
Sep-10	$ 700,000	$ 550,000	$ 150,000
Oct-10	$ 800,000	$ 550,000	$ 250,000
	$ 9,400,000	$ 6,600,000	$ 2,800,000

32. Q: Does this conclude your direct testimony at this time?

A: Yes, it does.

Delmarva Power & Light Company
Portfolio of Firm Transportation and Storage Services
As of November 1, 2009

(1)		(2)	(3)	(4)
		Daily (Mcf)	Annual (Mcf)	Contract Expiration
Firm Transportation				
	Transco Sentinel FT	24,155	8,816,575	2028
	Transco FT	55,356	20,204,940	2011
	Transco PS3	1,600	144,000	2011
	Columbia FT	26,009	9,493,285	2010
	TETCO ITP	9,662	3,526,630	2016
	National Fuel	2,705	987,325	2003
		119,487	43,172,755	
Firm Storage		Daily (Mcf)	Total Capacity	
	Transco GSS	15,450	1,171,557	2013
	Transco GSS	12,970	885,404	2013
	Columbia FSS	15,458	970,216	2013
	Transco LNG	840	6,970	2020
	Transco LG-A	2,000	15,000	2011
	National Fuel SS-2	2,180	330,000	1995
		48,898	3,379,147	
Subtotal Firm Capacity Available		168,385	46,551,902	
Supplemental Supply				
	Delmarva LNG	25,000	250,000	
Total Firm Peak Day Planned Capacity		**193,385**	**46,801,902**	

DELMARVA POWER & LIGHT COMPANY
FIRM TRANSPORTATION & STORAGE CONTRACT PORTFOLIO
2009-10 GCR PERIOD
SUMMARY OF PROJECTED FIXED GAS COSTS

	(1)	(2)	(3)	(4)	(5)
				2009-2010	2008-2009
1	PIPELINE CAPACITY & SUPPLY	CITYGATE MDQ	YEAR-TO-YEAR CHANGE	PROJECTED COSTS	PROJECTED COSTS
2	TRANSCO SENTINEL FT	24,155	$1,924,764	$5,046,308	$3,121,543
3	TRANSCO FT	54,800	$0	$9,257,069	$9,257,069
4	TRANSCO FT - (ESNG)	556	$0	$93,854	$93,854
5	TRANSCO LEIDY-LINE FT		$0	$217,032	$217,032
6	COLUMBIA FTS	26,009	$0	$1,919,112	$1,919,112
7	GULF FTS-1 & FTS-2		$0	$811,714	$811,714
8	TETCO ITP AND LATERAL	9,662	$0	$1,817,904	$1,817,904
9	NATIONAL/NOVA/TCPL	2,705	($6,935)	$198,152	$205,088
10	EASTERN SHORE FT365		$345,864	$4,433,940	$4,088,076
11	EASTERN SHORE T - 1		$0	$66,264	$66,264
12	EASTERN SHORE E-3 SURCHARGE		$263,683	$263,683	$0
13	SUBTOTAL	117,887	$2,263,693	$24,125,031	$21,597,655
14	STORAGE/SEASONAL SERVICES				
15	TRANSCO GSS	28,420	$0	$1,487,508	$1,487,508
16	COLUMBIA FSS	15,458	$0	$635,028	$635,028
17	COLUMBIA SST		$0	$830,970	$830,970
18	TRANSCO PS - 3	1,600	$137,595	$270,290	$132,695
19	PENN YORK SS - 2	2,180	($11,064)	$316,056	$327,120
20	TRANSCO ESS		($5,604)	$278,076	$283,680
21	COLUMBIA GULF WINTER FTS-1		$0	$12,890	$12,890
22	TRANSCO WSS		$0	$226,375	$226,375
23	SUBTOTAL	47,658	$11,630		$3,936,266
24	SUPPLEMENTAL & PEAKING SOURCES				
25	TRANSCO LGA	2,000	$0	$82,284	$82,284
26	TRANSCO LNG	840	$0	$36,732	$36,732
27	DELMARVA LNG	25,000			
28	SUBTOTAL	27,840	$0	$119,016	$119,016
29	TOTAL	193,385	$2,648,302	$28,301,239	$25,652,937

DELMARVA POWER & LIGHT COMPANY
Derivation of Transportation Balancing Fee
Proposed to be Effective November 1, 2009

	Services Required For Swing & System Reliability		
		Annual Cost	
1	TRANSCO GSS	$ 1,487,508	
2	COLUMBIA FSS	$ 635,028	
3	COLUMBIA SST	$ 830,970	
4	EASTERN SHORE	$ 4,260,901	
5	Claymont/Ridge Road & Hockessin Upgrades	892,199	
6	Estimated Upstream Costs of Balancing	$ 8,106,606	
	Projected System Throughput		
7	Projected Firm Sales	13,095,343	68.5%
8	Projected FT	5,086,052	26.6%
9	Projected IT	926,818	4.9%
10	Total Sales and Transportation Deliveries	19,108,213	100.00%
11	Proposed Balancing Fee [line 6/line10]	0.4242	per mcf

Schedule WTB - 4

Delmarva Power

2009-2010 Firm Sales and Sendout Estimate

	Nov-Oct TOTAL	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
1 Monthly Firm Sales Estimate	**13,095,343**	277,249	301,536	412,304	946,699	1,732,815	2,191,325	2,435,379	2,129,614	1,313,454	657,217	390,345	311,946	280,846	302,229	403,473
2 Company Use estimate	**10,138**	845	845	845	615	859	1,225	1,492	1,538	1,867	565	346	360	407	387	477
3 Subtotal Firm Sales	**13,105,481**	278,094	302,381	413,149	947,314	1,733,674	2,192,551	2,436,871	2,131,152	1,315,320	657,782	390,691	312,306	281,253	302,617	403,950
4 Cycle Billing and Lost and UAF	**262,110**	45,000	25,000	250,000	500,000	600,000	360,000	(300,000)	(450,000)	(450,000)	(170,000)	(40,000)	9,000	35,000	20,000	148,110
5 Total Sendout	**13,367,591**	323,094	327,381	663,149	1,447,314	2,333,674	2,552,551	2,136,871	1,681,152	865,320	487,782	350,691	321,306	316,253	322,617	552,060

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DELMARVA POWER & LIGHT COMPANY
SUMMARY OF ESTIMATED PRICES ($/MCF)
August 2007 - October 2008
15 Months Estimated

DESCRIPTION

	Component per MCF DEMAND CHARGES	AUG 2009	SEPT 2009	OCT 2009	NOV 2010	DEC 2010	JAN 2010	FEB 2010	MAR 2010
	TRANSCO								
1	Transco Sentinel FT	17.4098	17.4098	17.4098	17.4098	17.4098	17.4098	17.4098	17.4098
2	FT/PS-3 Demand Station 30	15.0701	15.0701	15.0701	15.0701	15.0701	15.0701	15.0701	15.0701
3	FT/PS-3 Demand Station 45	14.4484	14.4484	14.4484	14.4484	14.4484	14.4484	14.4484	14.4484
4	FT/PS-3 Demand Station 50	13.6259	13.6259	13.6259	13.6259	13.6259	13.6259	13.6259	13.6259
5	FT/PS-3 Demand Station 62	13.6259	13.6259	13.6259	13.6259	13.6259	13.6259	13.6259	13.6259
6	FT Demand WSS	3.0915	3.0915	3.0915	3.0915	3.0915	3.0915	3.0915	3.0915
7	Leidy-Line FT demand , $/MCF	3.7438	3.7438	3.7438	3.7438	3.7438	3.7438	3.7438	3.7438
8									
9									
10									
11	GSS Demand, $/MCF	3.1085	3.1085	3.1085	3.1085	3.1085	3.1085	3.1085	3.1085
12	GSS Capacity , $/MCF	0.0173	0.0173	0.0173	0.0173	0.0173	0.0173	0.0173	0.0173
13	WSS Demand, $/MCF	0.6507	0.6507	0.6507	0.6507	0.6507	0.6507	0.6507	0.6507
14	WSS Capacity , $/MCF	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076
15	LNG-peak Demand, $/MCF	1.4025	1.4025	1.4025	1.4025	1.4025	1.4025	1.4025	1.4025
16	LNG-peak Capacity, $/MCF	0.2701	0.2701	0.2701	0.2701	0.2701	0.2701	0.2701	0.2701
17	LGA Demand , $/MCF	1.4025	1.4025	1.4025	1.4025	1.4025	1.4025	1.4025	1.4025
18	LGA Capacity , $/MCF	0.2701	0.2701	0.2701	0.2701	0.2701	0.2701	0.2701	0.2701
19	ESS Demand,$/MCF	0.4536	0.4536	0.4536	0.4536	0.4536	0.4536	0.4536	0.4536
20	ESS Capacity, $/MCF	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453
	COLUMBIA								
21	FTS Demand, $/MCF	6.1489	6.1489	6.1489	6.1489	6.1489	6.1489	6.1489	6.1489
22	Columbia Gulf FTS-1 Demand	3.2551	3.2551	3.2551	3.2551	3.2551	3.2551	3.2551	3.2551
23	Columbia Gulf FTS-2 Demand	1.0974	1.0974	1.0974	1.0974	1.0974	1.0974	1.0974	1.0974
24	FSS Demand, $	1.5525	1.5525	1.5525	1.5525	1.5525	1.5525	1.5525	1.5525
25	FSS Capacity, $	0.0298	0.0298	0.0298	0.0298	0.0298	0.0298	0.0298	0.0298
26	SST Demand, $/MCF	5.9730	5.9730	5.9730	5.9730	5.9730	5.9730	5.9730	5.9730
	EASTERN SHORE								
27									
28									
29	FT-365 Demand, $	9.3220	9.3220	9.3220	9.3220	9.3220	9.3220	9.3220	9.3220
30	T-1, Demand $	7.3624	7.3624	7.3624	7.3624	7.3624	7.3624	7.3624	7.3624
	NATIONAL FUEL								
31	FT Demand, $/MCF	6.1038	6.1038	6.1038	6.1038	6.1038	6.1038	6.1038	6.1038
32	SS-2 Storage Demand, $	8.1470	8.1470	8.1470	8.1470	8.1470	8.1470	8.1470	8.1470
33	SS-2 Storage Capacity	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260
	TEXAS EASTERN								
34	ITP Demand $	22.3068	22.3068	22.3068	22.3068	22.3068	22.3068	22.3068	22.3068
35									

DELMARVA POWER & LIGHT COMPANY
SUMMARY OF ESTIMATED PRICES ($/MCF)
August 2007 - October 2008
15 Months Estimated

DESCRIPTION

	Component per MCF DEMAND CHARGES	APRIL 2010	MAY 2010	JUNE 2010	JULY 2010	AUG 2010	SEPT 2010	OCT 2010
	TRANSCO							
1	Transco Sentinel FT	17.4098	17.4098	17.4098	17.4098	17.4098	17.4098	17.4098
2	FT/PS-3 Demand Station 30	15.0701	15.0701	15.0701	15.0701	15.0701	15.0701	15.0701
3	FT/PS-3 Demand Station 45	14.4484	14.4484	14.4484	14.4484	14.4484	14.4484	14.4484
4	FT/PS-3 Demand Station 50	13.6259	13.6259	13.6259	13.6259	13.6259	13.6259	13.6259
5	FT/PS-3 Demand Station 62	13.6259	13.6259	13.6259	13.6259	13.6259	13.6259	13.6259
6	FT Demand WSS	3.0915	3.0915	3.0915	3.0915	3.0915	3.0915	3.0915
7	Leidy-Line FT demand , $/MCF	3.7438	3.7438	3.7438	3.7438	3.7438	3.7438	3.7438
8								
9								
10								
11	GSS Demand, $/MCF	3.1085	3.1085	3.1085	3.1085	3.1085	3.1085	3.1085
12	GSS Capacity , $/MCF	0.0173	0.0173	0.0173	0.0173	0.0173	0.0173	0.0173
13	WSS Demand, $/MCF	0.6507	0.6507	0.6507	0.6507	0.6507	0.6507	0.6507
14	WSS Capacity , $/MCF	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076
15	LNG-peak Demand, $/MCF	1.4025	1.4025	1.4025	1.4025	1.4025	1.4025	1.4025
16	LNG-peak Capacity, $/MCF	0.2701	0.2701	0.2701	0.2701	0.2701	0.2701	0.2701
17	LGA Demand , $/MCF	1.4025	1.4025	1.4025	1.4025	1.4025	1.4025	1.4025
18	LGA Capacity , $/MCF	0.2701	0.2701	0.2701	0.2701	0.2701	0.2701	0.2701
19	ESS Demand,$/MCF	0.4536	0.4536	0.4536	0.4536	0.4536	0.4536	0.4536
20	ESS Capacity, $/MCF	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453
	COLUMBIA							
21	FTS Demand, $/MCF	6.1489	6.1489	6.1489	6.1489	6.1489	6.1489	6.1489
22	Columbia Gulf FTS-1 Demand	3.2551	3.2551	3.2551	3.2551	3.2551	3.2551	3.2551
23	Columbia Gulf FTS-2 Demand	1.0974	1.0974	1.0974	1.0974	1.0974	1.0974	1.0974
24	FSS Demand, $	1.5525	1.5525	1.5525	1.5525	1.5525	1.5525	1.5525
25	FSS Capacity, $	0.0298	0.0298	0.0298	0.0298	0.0298	0.0298	0.0298
26	SST Demand, $/MCF	5.9730	5.9730	5.9730	5.9730	5.9730	5.9730	5.9730
	EASTERN SHORE							
27								
28								
29	FT-365 Demand, $	9.3220	9.3220	9.3220	9.3220	9.3220	9.3220	9.3220
30	T-1, Demand $	7.3624	7.3624	7.3624	7.3624	7.3624	7.3624	7.3624
	NATIONAL FUEL							
31	FT Demand, $/MCF	6.1038	6.1038	6.1038	6.1038	6.1038	6.1038	6.1038
32	SS-2 Storage Demand, $	8.1470	8.1470	8.1470	8.1470	8.1470	8.1470	8.1470
33	SS-2 Storage Capacity	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260
	TEXAS EASTERN							
34	ITP Demand $	22.3068	22.3068	22.3068	22.3068	22.3068	22.3068	22.3068
35								

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DELMARVA POWER & LIGHT COMPANY
SUMMARY OF ESTIMATED PRICES ($/MCF)
August 2007 - October 2008
15 Months Estimated

DESCRIPTION

	Component per MCF	AUG 2009	SEPT 2009	OCT 2009	NOV 2010	DEC 2010	JAN 2010	FEB 2010	MAR 2010
	COMMODITY CHARGES								
36									
37	Transco FT Base Commodity	10.0870	10.1173	10.0922	8.2116	8.2434	7.6226	7.5212	7.5195
38	Transco FT Swing Commodity	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
39	Transco FT Spot Commodity	3.6488	3.9472	4.2261	5.0029	5.7676	6.0780	6.1216	6.0649
40	Transco Leidy Line FT Commodity	3.7973	4.0809	4.3458	5.1190	5.8455	6.1405	6.1819	6.1281
41	Transco IT Commodity	4.2063	4.5037	4.7815	5.5921	6.3539	6.6632	6.7066	6.6502
42	GSS Inj, $/MCF	0.0446	0.0446	0.0446	0.0327	0.0327	0.0327	0.0327	0.0327
43	GSS W/D, $/MCF	0.0402	0.0402	0.0402	0.0302	0.0302	0.0302	0.0302	0.0302
44	WSS Inj or W/D, $/MCF	0.0134	0.0134	0.0134	0.0066	0.0066	0.0066	0.0066	0.0066
45	ESS Inj or W/D, $/MCF	0.0259	0.0259	0.0259	0.0094	0.0094	0.0094	0.0094	0.0094
46	LNG-peak Injection, $/MCF	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170
47	LNG-peakW/D, $/MCF	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170
48	LGA Inj or W/D, $/MCF	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170
49	Columbia FTS Base Commodity	3.6047	3.9041	4.1838	5.0001	5.7672	6.0786	6.1223	6.0655
50	Columbia FTS Swing Commodity	3.6047	3.9041	4.1838	5.0001	5.7672	6.0786	6.1223	6.0655
51	Columbia FTS Spot Commodity	3.6920	3.9876	4.2638	5.0697	5.8271	6.1346	6.1777	6.1216
52	Columbia SST Commodity	0.0178	0.0178	0.0178	0.0178	0.0178	0.0178	0.0178	0.0178
53	Columbia IT Commodity	3.6714	3.9691	4.2473	5.0589	5.8217	6.1314	6.1748	6.1183
54	FSS Inj & W/D, $	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158
55	ESNG FT-90 Commodity	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151
56	ESNG FT-181 Commodity	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151
57	ESNG FT-365 Commodity	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151
58	ESNG T-1 Commodity	0.0112	0.0112	0.0112	0.0112	0.0112	0.0112	0.0112	0.0112
59	National FT Commodity	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
60	SS-2 Inj & W/D	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110
61	Texas Eastern ITP Commodity	3.5227	3.8250	4.1074	4.9314	5.7359	6.0520	6.0964	6.0387

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DELMARVA POWER & LIGHT COMPANY
SUMMARY OF ESTIMATED PRICES ($/MCF)
August 2007 - October 2008
15 Months Estimated

DESCRIPTION

	Component per MCF	APRIL 2010	MAY 2010	JUNE 2010	JULY 2010	AUG 2010	SEPT 2010	OCT 2010
	COMMODITY CHARGES							
36								
37	Transco FT Base Commodity	8.1683	8.1751	8.1860	8.2000	8.2118	8.2218	8.2536
38	Transco FT Swing Commodity	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
39	Transco FT Spot Commodity	5.9941	6.0573	6.1629	6.2980	6.4004	6.4679	6.5877
40	Transco Leidy Line FT Commodity	6.0608	6.1208	6.2212	6.3496	6.4469	6.5110	6.6249
41	Transco IT Commodity	6.5797	6.6426	6.7479	6.8824	6.9844	7.0517	7.1711
42	GSS Inj, $/MCF	0.0327	0.0327	0.0327	0.0327	0.0327	0.0327	0.0327
43	GSS W/D, $/MCF	0.0302	0.0302	0.0302	0.0302	0.0302	0.0302	0.0302
44	WSS Inj or W/D, $/MCF	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066
45	ESS Inj or W/D, $/MCF	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094
46	LNG-peak Injection, $/MCF	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170
47	LNG-peakW/D, $/MCF	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170
48	LGA Inj or W/D, $/MCF	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170	1.4170
49	Columbia FTS Base Commodity	5.9945	6.0579	6.1639	6.2994	6.4021	6.4698	6.5900
50	Columbia FTS Swing Commodity	5.9945	6.0579	6.1639	6.2994	6.4021	6.4698	6.5900
51	Columbia FTS Spot Commodity	6.0515	6.1141	6.2187	6.3525	6.4539	6.5208	6.6395
52	Columbia SST Commodity	0.0178	0.0178	0.0178	0.0178	0.0178	0.0178	0.0178
53	Columbia IT Commodity	6.0477	6.1107	6.2161	6.3508	6.4530	6.5203	6.6399
54	FSS Inj & W/D, $	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158
55	ESNG FT-90 Commodity	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151
56	ESNG FT-181 Commodity	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151
57	ESNG FT-365 Commodity	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151	0.0151
58	ESNG T-1 Commodity	0.0112	0.0112	0.0112	0.0112	0.0112	0.0112	0.0112
59	National FT Commodity	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
60	SS-2 Inj & W/D	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110
61	Texas Eastern ITP Commodity	5.9352	5.9992	6.1062	6.2430	6.3467	6.4151	6.5364

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DELMARVA POWER & LIGHT COMPANY
SUMMARY OF BILLING DETERMINANTS (MCF)
August 2007 - October 2008
15 Months Estimated

DESCRIPTION

	DETERMINANT MCF	AUG 2009	SEPT 2009	OCT 2009	NOV 2010	DEC 2010	JAN 2010	FEB 2010	MAR 2010
	TRANSCO								
62	Transco Sentinel FT	24,155	24,155	24,155	24,155	24,155	24,155	24,155	24,155
63	FT Demand Sta 30	9,316	9,316	9,316	9,316	9,316	9,316	9,316	9,316
64	FT Demand Sta 45	13,700	13,700	13,700	13,700	13,700	13,700	13,700	13,700
65	FT Demand Sta 50	10,412	10,412	10,412	10,412	10,412	10,412	10,412	10,412
66	FT Demand Sta 62	21,372	21,372	21,372	21,372	21,372	21,372	21,372	21,372
67	FT Demand WSS	624	624	624	624	624	624	624	624
68	ESNG Capacity Release Transco FT Demand Station	95	95	95	95	95	95	95	95
69	ESNG Capacity Release Transco FT Demand Station	139	139	139	139	139	139	139	139
70	ESNG Capacity Release Transco FT Demand Station	105	105	105	105	105	105	105	105
71	ESNG Capacity Release Transco FT Demand Station	216	216	216	216	216	216	216	216
72	PS-3 Demand Sta 30	271	271	271	271	271	271	271	271
73	PS-3 Demand Sta 45	402	402	402	402	402	402	402	402
74	PS-3 Demand Sta 50	303	303	303	303	303	303	303	303
75	PS-3 Demand Sta 62	623	623	623	623	623	623	623	623
76	Leidy-Line FT Demand	4,831	4,831	4,831	4,831	4,831	4,831	4,831	4,831
77									
78					0	0	0	0	0
79					0	0	0	0	0
80	GSS Demand	28,420	28,420	28,420	28,420	28,420	28,420	28,420	28,420
81	GSS Capacity	2,056,961	2,056,961	2,056,961	2,056,961	2,056,961	2,056,961	2,056,961	2,056,961
82	WSS Demand	13,098	13,098	13,098	13,098	13,098	13,098	13,098	13,098
83	WSS Capacity	1,113,345	1,113,345	1,113,345	1,113,345	1,113,345	1,113,345	1,113,345	1,113,345
84	LNG-peak- Demand	840	840	840	840	840	840	840	840
85	LNG-peak Capacity	6,970	6,970	6,970	6,970	6,970	6,970	6,970	6,970
86	LGA Demand	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
87	LGA Capacity	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
88	ES Demand	25,546	25,546	25,546	25,546	25,546	25,546	25,546	25,546
89	ES Capacity	255,523	255,523	255,523	255,523	255,523	255,523	255,523	255,523
	COLUMBIA								
90	FTS Demand	26,009	26,009	26,009	26,009	26,009	26,009	26,009	26,009
91	Col Gulf FTS-1 Demand	18,989	18,989	18,989	18,989	18,989	18,989	18,989	18,989
92	Col Gulf FTS-2 Demand	6,292	6,292	6,292	6,292	6,292	6,292	6,292	6,292
93	FSS Demand	15,458	15,458	15,458	15,458	15,458	15,458	15,458	15,458
94	FSS Capacity	970,216	970,216	970,216	970,216	970,216	970,216	970,216	970,216
95	SST Demand	7,729	7,729	7,729	15,458	15,458	15,458	15,458	15,458
	EASTERN SHORE								
96									
97									
98	FT 365 Demand	39,637	39,637	39,637	39,637	39,637	39,637	39,637	39,637
99	T-1 Demand	750	750	750	750	750	750	750	750
	NATIONAL FUEL								
100	FT Demand	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705
101	SS-2 Storage Demand	2,180	2,180	2,180	2,180	2,180	2,180	2,180	2,180
102	SS-2 Capacity	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000
	TEXAS EASTERN								
103	ITP Demand	9,662	9,662	9,662	9,662	9,662	9,662	9,662	9,662
104									

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DELMARVA POWER & LIGHT COMPANY
SUMMARY OF BILLING DETERMINANTS (MCF)
August 2007 - October 2008
15 Months Estimated

DESCRIPTION

	DETERMINANT MCF	APRIL 2010	MAY 2010	JUNE 2010	JULY 2010	AUG 2010	SEPT 2010	OCT 2010
	TRANSCO							
62	Transco Sentinel FT	24,155	24,155	24,155	24,155	24,155	24,155	24,155
63	FT Demand Sta 30	9,316	9,316	9,316	9,316	9,316	9,316	9,316
64	FT Demand Sta 45	13,700	13,700	13,700	13,700	13,700	13,700	13,700
65	FT Demand Sta 50	10,412	10,412	10,412	10,412	10,412	10,412	10,412
66	FT Demand Sta 62	21,372	21,372	21,372	21,372	21,372	21,372	21,372
67	FT Demand WSS	624	624	624	624	624	624	624
68	ESNG Capacity Release Transco FT Demand Station	95	95	95	95	95	95	95
69	ESNG Capacity Release Transco FT Demand Station	139	139	139	139	139	139	139
70	ESNG Capacity Release Transco FT Demand Station	105	105	105	105	105	105	105
71	ESNG Capacity Release Transco FT Demand Station	216	216	216	216	216	216	216
72	PS-3 Demand Sta 30	271	271	271	271	271	271	271
73	PS-3 Demand Sta 45	402	402	402	402	402	402	402
74	PS-3 Demand Sta 50	303	303	303	303	303	303	303
75	PS-3 Demand Sta 62	623	623	623	623	623	623	623
76	Leidy-Line FT Demand	4,831	4,831	4,831	4,831	4,831	4,831	4,831
77								
78		0	0	0	0	0	0	0
79		0	0	0	0	0	0	0
80	GSS Demand	28,420	28,420	28,420	28,420	28,420	28,420	28,420
81	GSS Capacity	2,056,961	2,056,961	2,056,961	2,056,961	2,056,961	2,056,961	2,056,961
82	WSS Demand	13,098	13,098	13,098	13,098	13,098	13,098	13,098
83	WSS Capacity	1,113,345	1,113,345	1,113,345	1,113,345	1,113,345	1,113,345	1,113,345
84	LNG-peak- Demand	840	840	840	840	840	840	840
85	LNG-peak Capacity	6,970	6,970	6,970	6,970	6,970	6,970	6,970
86	LGA Demand	2,000	2,000	2,000	2,000	2,000	2,000	2,000
87	LGA Capacity	15,000	15,000	15,000	15,000	15,000	15,000	15,000
88	ES Demand	25,546	25,546	25,546	25,546	25,546	25,546	25,546
89	ES Capacity	255,523	255,523	255,523	255,523	255,523	255,523	255,523
	COLUMBIA							
90	FTS Demand	26,009	26,009	26,009	26,009	26,009	26,009	26,009
91	Col Gulf FTS-1 Demand	18,989	18,989	18,989	18,989	18,989	18,989	18,989
92	Col Gulf FTS-2 Demand	6,292	6,292	6,292	6,292	6,292	6,292	6,292
93	FSS Demand	15,458	15,458	15,458	15,458	15,458	15,458	15,458
94	FSS Capacity	970,216	970,216	970,216	970,216	970,216	970,216	970,216
95	SST Demand	15,458	7,729	7,729	7,729	7,729	7,729	7,729
	EASTERN SHORE							
96								
97								
98	FT 365 Demand	39,637	39,637	39,637	39,637	39,637	39,637	39,637
99	T-1 Demand	750	750	750	750	750	750	750
	NATIONAL FUEL							
100	FT Demand	2,705	2,705	2,705	2,705	2,705	2,705	2,705
101	SS-2 Storage Demand	2,180	2,180	2,180	2,180	2,180	2,180	2,180
102	SS-2 Capacity	330,000	330,000	330,000	330,000	330,000	330,000	330,000
	TEXAS EASTERN							
103	ITP Demand	9,662	9,662	9,662	9,662	9,662	9,662	9,662
104								

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DELMARVA POWER & LIGHT COMPANY
SUMMARY OF GAS SUPPLY (MCF)
August 2007 - October 2008
15 Months Estimated

	DESCRIPTION	AUG 2009	SEPT 2009	OCT 2009	NOV 2010	DEC 2010	JAN 2010	FEB 2010	MAR 2010
	FIRM SUPPLY								
105									
106									
107	Transco FT Base	496,812	475,362	495,845	807,633	785,894	839,614	744,734	817,005
108	Transco FT & PS-3(WSS W/D)	0	0	0	0	0	0	0	0
109	Transco FT & PS-3(ESS W/D)	20688	20688	20688	0	0	100,000	100,000	40,000
109	Transco Spot	3,353	4,824	106,617	229,741	387,542	207,490	222,714	196,670
110	TOTAL TRANSCO FT SUPPLY(LESS WSS/ESS)	500,165	480,186	602,462	1,037,374	1,173,436	1,047,104	967,448	1,013,675
111	Columbia Spot	0	0	0	0	0	0	0	0
112		0	0	0	0	0	0	0	0
113	Columbia Base	194,414	188,062	203,546	187,037	182,418	191,789	173,219	192,716
114	TOTAL COLUMBIA FTS-1 SUPPLY	194,414	188,062	203,546	187,037	182,418	191,789	173,219	192,716
115	TEXAS EASTERN ITP SUPPLY	0	0	0	0	299,522	299,522	270,536	149,761
116	OTHER FIRM SUPPLY	0	0	0	0	0	0	0	0
117	TOTAL FIRM SUPPLY (MCF)	694,579	668,248	806,008	1,224,411	1,655,376	1,538,415	1,411,203	1,356,152
	INTERRUPTIBLE SUPPLY								
118	TRANSCO IT SUPPLY	0	0	0	0	0	0	0	0
119	COLUMBIA ITS SUPPLY	0	0	0	0	0	0	0	0
120	TEXAS EASTERN IT-1 SUPPLY	0	0	0	0	0	0	0	0
121	OTHER NON-FIRM SUPPLY	0	0	0	0	0	0	0	0
122	TOTAL NON-FIRM SUPPLY (MCF)	0	0	0	0	0	0	0	0
	STORAGE								
123	GSS GROSS INJECTION TO STORAGE(INCL FUE	(222,636)	(222,636)	(222,636)	0	0	0	0	0
124	WSS GROSS INJECTION TO STORAGE(INCL FUE	0	0	0	0	0	0	0	0
125	ESS GROSS INJECTION TO STORAGE(INCL FUE	(40,276)	(40,276)	(22,756)	0	0	0	0	0
126	PYS GROSS INJECTION TO STORAGE(INCL FUE	(39,355)	(39,355)	0	0	0	0	0	0
127	Transco LNG-peak GROSS INJ (INCL FUEL)	(1,306)	(1,264)	(902)	0	0	0	0	0
128	LGA GROSS INJECTION TO STORAGE(INCL FUE	(2,646)	(2,646)	(2,208)	0	0	0	0	0
129	FSS: GROSS INJECTION TO STORAGE (INCL FU]	(105,722)	(105,722)	(49,920)	0	0	0	0	0
130	IMBALANCES	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
131	TOTAL INJ EXT STORAGES	(411,942)	(411,900)	(298,423)	0	0	0	0	0
132	LNG INJECTED TO STORAGE	(34,100)	0	(21,793)	0	0	0	0	0
133	TOTAL STORAGE INJECTED	(446,042)	(411,900)	(320,216)	0	0	0	0	0
134	GSS WITHDRAWN; REC'D AT CITYGATE	40,580	40,580	40,580	100,223	284,203	500,000	400,000	200,000
135	WSS WITHDRAWN; REC'D AT CITYGATE	0	0	0	0	0	0	0	0
136	ESS WITHDRAWN; REC'D AT CITYGATE	20,688	20,688	20,688	0	0	100,000	100,000	40,000
137	PYS WITHDRAWN; REC'D AT CITYGATE	0	0	0	67,680	69,936	69,936	63,168	30,000
138	Transco LNG-peak WITHDRAWN; REC'D AT CG	0	0	0	0	0	6,700	0	0
139	LGA WITHDRAWN; REC'D AT CITYGATE	0	0	0	0	0	7,500	7,500	0
140	FSS WITHDRAWN; REC'D AT CITYGATE	0	0	0	50,000	309,159	225,000	150,000	50,000
141	IMBALANCES	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
142	TOTAL W/D EXT STORAGES	61,268	61,268	61,268	217,903	663,298	909,136	720,668	320,000
143	LNG WITHDRAWN (INCLUDING BOILOFF)	6,448	5,000	5,000	5,000	15,000	105,000	5,000	5,000
144	TOTAL STORAGE WITHDRAWN, MCF	67,716	66,268	66,268	222,903	678,298	1,014,136	725,668	325,000
145	TOTAL NET STORAGE, MCF	(378,326)	(345,632)	(253,948)	222,903	678,298	1,014,136	725,668	325,000
146	TOTAL SUPPLY AVAILABLE FOR SENDOUT	316,253	322,616	552,060	1,447,314	2,333,674	2,552,551	2,136,871	1,681,152
147	PRIOR PERIOD ADJUSTMENTS	0	0	0	0	0	0	0	0
148	NET SUPPLY AVAILABLE FOR SENDOUT	316,253	322,616	552,060	1,447,314	2,333,674	2,552,551	2,136,871	1,681,152

DELMARVA POWER & LIGHT COMPANY
SUMMARY OF GAS SUPPLY (MCF)
August 2007 - October 2008
15 Months Estimated

	DESCRIPTION	APRIL 2010	MAY 2010	JUNE 2010	JULY 2010	AUG 2010	SEPT 2010	OCT 2010	GCR TOTAL
	FIRM SUPPLY								
105									
106									
107	Transco FT Base	644,251	656,522	621,546	624,831	610,821	580,097	565,894	8,298,842
108	Transco FT & PS-3(WSS W/D)	0	0	0	0	0	0	0	0
109	Transco FT & PS-3(ESS W/D)	0	0	0	0	0	0	0	240,000
109	Transco Spot	429,749	185,624	160,286	77,186	14,045	0	16,220	2,127,267
110	TOTAL TRANSCO FT SUPPLY(LESS WSS/ESS)	1,074,000	842,146	781,832	702,017	624,866	580,097	582,114	10,426,109
111	Columbia Spot	0	0	0	0	0	0	0	0
112		0	0	0	0	0	0	0	0
113	Columbia Base	187,350	194,221	188,102	92,352	13,130	60,284	91,234	1,753,852
114	TOTAL COLUMBIA FTS-1 SUPPLY	187,350	194,221	188,102	92,352	13,130	60,284	91,234	1,753,852
115	TEXAS EASTERN ITP SUPPLY	144,930	0	0	0	0	0	0	1,164,271
116	OTHER FIRM SUPPLY	0	0	0	0	0	0	0	0
117	TOTAL FIRM SUPPLY (MCF)	1,406,280	1,036,367	969,934	794,369	637,996	640,381	673,348	13,344,232
	INTERRUPTIBLE SUPPLY								
118	TRANSCO IT SUPPLY	0	0	0	0	0	0	0	0
119	COLUMBIA ITS SUPPLY	0	0	0	0	0	0	0	0
120	TEXAS EASTERN IT-1 SUPPLY	0	0	0	0	0	0	0	0
121	OTHER NON-FIRM SUPPLY	0	0	0	0	0	0	0	0
122	TOTAL NON-FIRM SUPPLY (MCF)	0	0	0	0	0	0	0	0
	STORAGE								
123	GSS GROSS INJECTION TO STORAGE(INCL FUE	(261,473)	(261,473)	(356,554)	(212,691)	(150,391)	(145,540)	(56,942)	(1,445,063)
124	WSS GROSS INJECTION TO STORAGE(INCL FUE	0	0	0	0	0	0	0	0
125	ESS GROSS INJECTION TO STORAGE(INCL FUE	(40,276)	(40,276)	(40,276)	(40,276)	(40,276)	(40,276)	(10,367)	(252,025)
126	PYS GROSS INJECTION TO STORAGE(INCL FUE	(48,001)	(48,001)	(48,001)	(48,001)	(47,333)	(48,001)	(26,064)	(313,400)
127	Transco LNG-peak GROSS INJ (INCL FUEL)	(1,264)	(1,306)	(1,264)	(1,306)	(1,306)	(1,264)	(179)	(7,891)
128	LGA GROSS INJECTION TO STORAGE(INCL FUE	(1,414)	(2,735)	(2,646)	(2,735)	(2,646)	(2,646)	(2,735)	(17,558)
129	FSS: GROSS INJECTION TO STORAGE (INCL FUI	(193,531)	(164,794)	(145,501)	(135,855)	(49,037)	(49,037)	0	(737,755)
130	IMBALANCES	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
131	TOTAL INJ EXT STORAGES	(545,959)	(518,585)	(594,243)	(440,863)	(290,990)	(286,764)	(96,288)	(2,773,692)
132	LNG INJECTED TO STORAGE	0	(35,000)	(30,000)	(37,200)	(37,200)	(36,000)	(30,000)	(205,400)
133	TOTAL STORAGE INJECTED	(545,959)	(553,585)	(624,243)	(478,063)	(328,190)	(322,764)	(126,288)	(2,979,092)
134	GSS WITHDRAWN; REC'D AT CITYGATE	0	0	0	0	0	0	0	1,484,426
135	WSS WITHDRAWN; REC'D AT CITYGATE	0	0	0	0	0	0	0	0
136	ESS WITHDRAWN; REC'D AT CITYGATE	0	0	0	0	0	0	0	240,000
137	PYS WITHDRAWN; REC'D AT CITYGATE	0	0	0	0	0	0	0	300,720
138	Transco LNG-peak WITHDRAWN; REC'D AT CG	0	0	0	0	0	0	0	6,700
139	LGA WITHDRAWN; REC'D AT CITYGATE	0	0	0	0	0	0	0	15,000
140	FSS WITHDRAWN; REC'D AT CITYGATE	0	0	0	0	0	0	0	784,159
141	IMBALANCES	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
142	TOTAL W/D EXT STORAGES	0	0	0	0	0	0	0	2,831,005
143	LNG WITHDRAWN (INCLUDING BOILOFF)	5,000	5,000	5,000	5,000	6,448	5,000	5,000	171,448
144	TOTAL STORAGE WITHDRAWN, MCF	5,000	5,000	5,000	5,000	6,448	5,000	5,000	3,002,453
145	TOTAL NET STORAGE, MCF	(540,959)	(548,585)	(619,243)	(473,063)	(321,742)	(317,764)	(121,288)	23,361
146	TOTAL SUPPLY AVAILABLE FOR SENDOUT	865,321	487,782	350,691	321,306	316,254	322,617	552,060	13,367,593
147	PRIOR PERIOD ADJUSTMENTS	0	0	0	0	0	0	0	0
148	NET SUPPLY AVAILABLE FOR SENDOUT	865,321	487,782	350,691	321,306	316,254	322,617	552,060	13,367,593

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DELMARVA POWER & LIGHT COMPANY
SUMMARY OF GAS DEMAND:SENDOUT (MCF)
August 2007 - October 2008
15 Months Estimated

	DESCRIPTION	AUG 2009	SEPT 2009	OCT 2009	NOV 2010	DEC 2010	JAN 2010	FEB 2010	MAR 2010
	DEMAND								
149	FIRM BILLED SALES VOLUMES, MCF	280,846	302,229	403,473	946,699	1,732,815	2,191,325	2,435,379	2,129,614
150	CO. USE, MCF	407	387	477	615	859	1,225	1,492	1,538
151	Unaccounted For & Cycle Billing Adjustment	35,000	20,000	148,110	500,000	600,000	360,000	(300,000)	(450,000)
152	TOTAL FIRM SENDOUT REQUIRED, MCF	316,253	322,617	552,060	1,447,314	2,333,674	2,552,551	2,136,871	1,681,152
153	FLEXIBLY PRICED GAS SUPPLY SERVICE	0	0	0	0	0	0	0	0
154									
155	TOTAL NON-FIRM SENDOUT REQUIRED	0	0	0	0	0	0	0	0
156	TOTAL SENDOUT REQUIRED, MCF:	316,253	322,617	552,060	1,447,314	2,333,674	2,552,551	2,136,871	1,681,152

DELMARVA POWER & LIGHT COMPANY
SUMMARY OF GAS DEMAND:SENDOUT (MCF)
August 2007 - October 2008
15 Months Estimated

	DESCRIPTION	APRIL 2010	MAY 2010	JUNE 2010	JULY 2010	AUG 2010	SEPT 2010	OCT 2010	Nov08-Oct09 GCR TOTAL
	DEMAND								
149	FIRM BILLED SALES VOLUMES, MCF	1,313,454	657,217	390,345	311,946	280,846	302,229	403,473	13,095,343
150	CO. USE, MCF	1,867	565	346	360	407	387	477	10,138
151	Unaccounted For & Cycle Billing Adjustment	(450,000)	(170,000)	(40,000)	9,000	35,000	20,000	148,110	262,110
152	TOTAL FIRM SENDOUT REQUIRED, MCF	865,320	487,782	350,691	321,306	316,253	322,617	552,060	13,367,591
153	FLEXIBLY PRICED GAS SUPPLY SERVICE	0	0	0	0	0	0	0	0
154									
155	TOTAL NON-FIRM SENDOUT REQUIRED	0	0	0	0	0	0	0	0
156	TOTAL SENDOUT REQUIRED, MCF:	865,320	487,782	350,691	321,306	316,253	322,617	552,060	13,367,591

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DELMARVA POWER & LIGHT COMPANY
SUMMARY OF GAS COSTS ($)
August 2007 - October 2008
15 Months Estimated

	DESCRIPTION	AUG 2009	SEPT 2009	OCT 2009	NOV 2010	DEC 2010	JAN 2010	FEB 2010	MAR 2010
	TRANSPORTATION COMMODITY CHAR(								
157									
158	Transco Base	5,011,351	4,809,394	5,004,164	6,631,955	6,478,412	6,400,074	5,601,320	6,143,482
159	Transco FT spot	84,084	96,868	518,987	1,115,170	2,202,867	1,828,830	1,943,888	1,400,970
160	SUBTOTAL TRANSCO FT: COMMODITY	5,095,435	4,906,262	5,523,151	7,747,125	8,681,278	8,228,903	7,545,207	7,544,452
161	Columbia Leach	0	0	0	0	0	0	0	0
162	Columbia swing	0	0	0	0	0	0	0	0
163	Columbia spot	700,796	734,208	851,599	935,202	1,052,041	1,165,814	1,060,506	1,168,922
164	SUBTOTAL COLUMBIA FTS: COMMODITY	700,796	734,208	851,599	935,202	1,052,041	1,165,814	1,060,506	1,168,922
165	TEXAS EASTERN ITP SUPPLY	0	0	0	0	1,718,043	1,812,712	1,649,289	904,363
166	FT-90: ESNG COMMODITY CHARGE	0	0	0	0	0	0	0	0
167	FT-181: ESNG COMMODITY CHARGE	0	0	0	0	0	0	0	0
168	FT-365: ESNG COMMODITY CHARGE	0	0	0	0	0	0	0	0
169	T-1: ESNG COMMODITY CHARGE	0	0	0	0	0	0	0	0
170	NATIONAL FT COMMODITY	113	109	113	109	113	113	102	113
171	TRANSCO LEIDY LINE TRANSPORT	3,050	2,952	3,050	5,414	5,594	5,594	5,053	4,142
172	WSS: TRANSPORT CHARGE:	0	0	0	0	0	0	0	0
173	ESS: TRANSPORT CHARGE:	1,504	1,504	1,583	0	0	6,104	6,104	2,441
174	COLUMBIA SST TRANSPORT	0	0	0	890	5,504	4,005	2,670	890
175	OTHER FIRM PURCHASES	0	0	0	0	0	0	0	0
176	TOTAL COMMODITY FIRM TRANSPORT $	5,800,899	5,645,035	6,379,495	8,688,741	11,462,573	11,223,246	10,268,931	9,625,323
177	TRANSCO IT: DELIVERED COMMODITY	0	0	0	0	0	0	0	0
178	COLUMBIA ITS: DELIVERED COMMODITY	0	0	0	0	0	0	0	0
179	TEXAS EASTERN IT-1 COMMODITY	0	0	0	0	0	0	0	0
180	OTHER NON-FIRM PURCHASES	0	0	0	0	0	0	0	0
181	TOTAL COMMODITY NONFIRM TRANSPORT $	0	0	0	0	0	0	0	0
182	TOTAL TRANSPORTATION COMMODITY $	5,800,899	5,645,035	6,379,495	8,688,741	11,462,573	11,223,246	10,268,931	9,625,323

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DELMARVA POWER & LIGHT COMPANY
SUMMARY OF GAS COSTS ($)
August 2007 - October 2008
15 Months Estimated

	DESCRIPTION	APRIL 2010	MAY 2010	JUNE 2010	JULY 2010	AUG 2010	SEPT 2010	OCT 2010	Nov08-Oct09 GCR TOTAL
	TRANSPORTATION COMMODITY CHAR(								
157									
158	Transco Base	5,262,458	5,367,139	5,087,967	5,123,589	5,015,920	4,769,425	4,670,649	66,552,389
159	Transco FT spot	2,550,450	1,097,383	964,579	474,954	87,867	0	104,523	13,771,480
160	SUBTOTAL TRANSCO FT: COMMODITY	7,812,908	6,464,522	6,052,546	5,598,543	5,103,787	4,769,425	4,775,172	80,323,869
161	Columbia Leach	0	0	0	0	0	0	0	0
162	Columbia swing	0	0	0	0	0	0	0	0
163	Columbia spot	1,123,067	1,176,565	1,159,435	581,759	84,059	390,027	601,235	10,498,634
164	SUBTOTAL COLUMBIA FTS: COMMODITY	1,123,067	1,176,565	1,159,435	581,759	84,059	390,027	601,235	10,498,634
165	TEXAS EASTERN ITP SUPPLY	860,190	0	0	0	0	0	0	6,944,597
166	FT-90: ESNG COMMODITY CHARGE	0	0	0	0	0	0	0	
167	FT-181: ESNG COMMODITY CHARGE	0	0	0	0	0	0	0	
168	FT-365: ESNG COMMODITY CHARGE	0	0	0	0	0	0	0	0
169	T-1: ESNG COMMODITY CHARGE	0	0	0	0	0	0	0	0
170	NATIONAL FT COMMODITY	109	113	109	113	113	109	113	1,329
171	TRANSCO LEIDY LINE TRANSPORT	2,952	3,050	2,952	3,050	3,050	2,952	3,050	46,853
172	WSS: TRANSPORT CHARGE:	0	0	0	0	0	0	0	0
173	ESS: TRANSPORT CHARGE:	322	322	322	322	322	322	83	16,664
174	COLUMBIA SST TRANSPORT	0	0	0	0	0	0	0	13,960
175	OTHER FIRM PURCHASES	0	0	0	0	0	0	0	0
176	TOTAL COMMODITY FIRM TRANSPORT $	9,799,549	7,644,572	7,215,364	6,183,787	5,191,331	5,162,836	5,379,653	97,845,905
177	TRANSCO IT: DELIVERED COMMODITY	0	0	0	0	0	0	0	0
178	COLUMBIA ITS: DELIVERED COMMODITY	0	0	0	0	0	0	0	0
179	TEXAS EASTERN IT-1 COMMODITY	0	0	0	0	0	0	0	0
180	OTHER NON-FIRM PURCHASES	0	0	0	0	0	0	0	0
181	TOTAL COMMODITY NONFIRM TRANSPORT $	0	0	0	0	0	0	0	0
182	TOTAL TRANSPORTATION COMMODITY $	9,799,549	7,644,572	7,215,364	6,183,787	5,191,331	5,162,836	5,379,653	97,845,905

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DELMARVA POWER & LIGHT COMPANY
SUMMARY OF GAS COSTS ($)
August 2007 - October 2008
15 Months Estimated

	DESCRIPTION	AUG 2009	SEPT 2009	OCT 2009	NOV 2010	DEC 2010	JAN 2010	FEB 2010	MAR 2010
	STORAGE COMMODITY CHARGES, $								
183	GSS: CREDIT COMMODITY INJECTED	(1,728,226)	(1,730,556)	(845,429)	0	0	0	0	0
184	WSS: CREDIT COMMDTY INJ (+ FUEL)	0	0	0	0	0	0	0	0
185	ESS: CREDIT COMMDTY INJ (+ FUEL)	(234,878)	(235,195)	(311,046)	0	0	0	0	0
186	PYS: CREDIT COMMDTY INJ (+ FUEL)	(311,720)	(312,141)	0	0	0	0	0	0
187	Transco LNG-peak: CREDIT COMMODITY INJ	(14,562)	(14,108)	(10,086)	0	0	0	0	0
188	LGA: CREDIT COMMODITY INJECTED	(25,752)	(25,783)	(21,550)	0	0	0	0	0
189	FSS: CR INJ(+FUEL)	(818,222)	(819,325)	(387,588)	0	0	0	0	0
190	IMBALANCE	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
191	PRIOR PERIOD ADJUSTMENTS	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
192	TOTAL CREDIT STORAGE GAS INJ-808.2	(3,133,360)	(3,137,108)	(1,575,699)	0	0	0	0	0
193	LNG: CREDIT INJECTED-808.201	(299,655)	0	(192,091)	0	0	0	0	0
194	LNG: PRIOR PERIOD ADJUSTMENT	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
195	TOTAL CREDIT LNG GAS INJ-808.201	(299,655)	0	(192,091)	0	0	0	0	0
196	GSS: DEBIT COMMODITY WITHDRAWN	335,389	334,352	333,594	693,631	2,452,941	3,946,445	3,254,358	1,870,184
197	WSS: DEBIT COMMODITY (W/D +FUEL)	0	0	0	0	0	0	0	0
198	ESS: DEBIT COMMODITY (W/D +FUEL)	186,010	180,949	177,664	0	0	759,268	776,674	333,599
199	PYS: DEBIT COMMODITY (W/D +FUEL)	0	0	0	434,214	450,333	452,691	412,346	199,224
200	Transco LNG-peak: DEBIT COMMODITY WD	0	0	0	0	0	62,717	0	0
201	LG-A: DEBIT COMMODITY WITHDRAWN	0	0	0	0	0	70,259	66,838	0
202	FSS: DEBIT COMMODITY (W/D +FUEL)	0	0	0	311,555	2,412,412	1,888,009	1,420,676	797,565
203	AMORTIZATION OF STORAGE OPTION SETTLEI	0	0	0	0	0	0	0	0
204	PRIOR PERIOD ADJUSTMENTS	0	0	0	0	0	0	0	0
205	TOTAL DEBIT STORAGE GAS W/D-808.1	521,399	515,301	511,258	1,439,400	5,315,686	7,179,389	5,930,892	3,200,572
206	LNG: DEBIT WITHDRAWAL 808.101	73,230	54,730	54,730	54,589	163,768	1,146,379	54,589	54,589
207	LNG: PRIOR PERIOD ADJUSTMENT	0	0	0	0	0	0	0	0
208	TOTAL DEBIT LNG GAS W/D-808.101	73,230	54,730	54,730	54,589	163,768	1,146,379	54,589	54,589
209	GSS: INJ & W/D CHARGES	11,566	11,566	11,566	3,029	8,589	15,111	12,089	6,044
210	WSS: INJ & W/D CHARGES	0	0	0	0	0	0	0	0
211	ESS: INJ & W/D CHARGES	1,581	1,581	1,126	0	0	942	942	377
212	PYS: INJ & W/D CHARGES	432	432	0	743	767	767	693	329
213	Transco LNG: INJ & W/D CHARGES	1,851	1,791	1,279	0	0	0	0	0
214	Transco LNG: INJ CHARGES	0	0	0	0	0	9,494	0	0
215	LGA: W/D CHARGES	3,750	3,750	3,129	0	0	10,627	10,627	0
216	FSS: INJ & W/D CHARGES	1,674	1,674	791	792	4,896	3,563	2,375	792
217	SUBTOTAL INJ & W/D CHARGES	20,854	20,794	17,891	4,564	14,252	40,504	26,726	7,542
218	TOTAL NET STORAGE $	(2,817,532)	(2,546,283)	(1,183,911)	1,498,553	5,493,706	8,366,272	6,012,207	3,262,703
219	WACOG SUPPLY EXPENSE	5,800,899	5,645,035	6,379,495	8,688,741	11,462,573	11,223,246	10,268,931	9,625,323
220	WACOG VOLUMES	694,579	668,248	806,008	1,224,411	1,655,376	1,538,415	1,411,203	1,356,152
221	Average STORAGE W/D WACOG				$ 6.7229	$ 8.0993	$ 8.2497	$ 8.2351	$ 10.0391

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DELMARVA POWER & LIGHT COMPANY
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	DESCRIPTION	APRIL 2010	MAY 2010	JUNE 2010	JULY 2010	AUG 2010	SEPT 2010	OCT 2010	Nov08-Oct09 GCR TOTAL
	STORAGE COMMODITY CHARGES, $								
183	GSS: CREDIT COMMODITY INJECTED	(1,917,587)	(1,917,023)	(2,612,694)	(1,556,818)	(1,099,648)	(1,063,284)	(415,549)	(10,582,603)
184	WSS: CREDIT COMMDTY INJ (+ FUEL)	0	0	0	0	0	0	0	0
185	ESS: CREDIT COMMDTY INJ (+ FUEL)	(233,982)	(236,417)	(240,488)	(245,692)	(249,638)	(252,240)	(66,115)	(1,524,572)
186	PYS: CREDIT COMMDTY INJ (+ FUEL)	(342,288)	(342,187)	(342,000)	(341,626)	(331,980)	(340,979)	(184,948)	(2,226,008)
187	Transco LNG-peak: CREDIT COMMODITY INJ	(11,290)	(11,756)	(11,522)	(12,098)	(12,244)	(11,942)	(1,715)	(72,567)
188	LGA: CREDIT COMMODITY INJECTED	(10,625)	(20,735)	(20,371)	(21,452)	(21,055)	(21,249)	(22,319)	(137,806)
189	FSS: CR INJ(+FUEL)	(1,367,250)	(1,163,888)	(1,027,066)	(957,932)	(345,402)	(345,113)	0	(5,206,651)
190	IMBALANCE	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
191	PRIOR PERIOD ADJUSTMENTS	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
192	TOTAL CREDIT STORAGE GAS INJ-808.2	(3,883,022)	(3,692,006)	(4,254,141)	(3,135,618)	(2,059,967)	(2,034,807)	(690,646)	(19,750,207)
193	LNG: CREDIT INJECTED-808.201	0	(236,522)	(205,993)	(260,600)	(264,517)	(258,485)	(219,102)	(1,445,219)
194	LNG: PRIOR PERIOD ADJUSTMENT	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
195	TOTAL CREDIT LNG GAS INJ-808.201	0	(236,522)	(205,993)	(260,600)	(264,517)	(258,485)	(219,102)	(1,445,219)
196	GSS: DEBIT COMMODITY WITHDRAWN	0	0	0	0	0	0	0	12,217,559
197	WSS: DEBIT COMMODITY (W/D +FUEL)	0	0	0	0	0	0	0	0
198	ESS: DEBIT COMMODITY (W/D +FUEL)	0	0	0	0	0	0	0	1,869,541
199	PYS: DEBIT COMMODITY (W/D +FUEL)	0	0	0	0	0	0	0	1,948,808
200	Transco LNG-peak: DEBIT COMMODITY WD	0	0	0	0	0	0	0	62,717
201	LG-A: DEBIT COMMODITY WITHDRAWN	0	0	0	0	0	0	0	137,097
202	FSS: DEBIT COMMODITY (W/D +FUEL)	0	0	0	0	0	0	0	6,830,217
203	AMORTIZATION OF STORAGE OPTION SETTLEI	0	0	0	0	0	0	0	0
204	PRIOR PERIOD ADJUSTMENTS	0	0	0	0	0	0	0	0
205	TOTAL DEBIT STORAGE GAS W/D-808.1	0	0	0	0	0	0	0	23,065,938
206	LNG: DEBIT WITHDRAWAL 808.101	54,589	54,589	46,203	43,018	52,814	39,805	39,122	1,804,054
207	LNG: PRIOR PERIOD ADJUSTMENT	0	0	0	0	0	0	0	0
208	TOTAL DEBIT LNG GAS W/D-808.101	54,589	54,589	46,203	43,018	52,814	39,805	39,122	1,804,054
209	GSS: INJ & W/D CHARGES	8,552	8,552	11,661	6,956	4,919	4,760	1,862	92,124
210	WSS: INJ & W/D CHARGES	0	0	0	0	0	0	0	0
211	ESS: INJ & W/D CHARGES	379	379	379	379	379	379	98	0
212	PYS: INJ & W/D CHARGES	527	527	527	527	519	527	286	6,739
213	Transco LNG: INJ & W/D CHARGES	1,791	1,851	1,791	1,851	1,851	1,791	254	11,180
214	Transco LNG: INJ CHARGES	0	0	0	0	0	0	0	9,494
215	LGA: W/D CHARGES	2,004	3,875	3,750	3,875	3,750	3,750	3,876	46,134
216	FSS: INJ & W/D CHARGES	3,065	2,610	2,304	2,151	777	777	0	24,102
217	SUBTOTAL INJ & W/D CHARGES	16,318	17,794	20,412	15,739	12,195	11,984	6,876	194,406
218	TOTAL NET STORAGE $	(3,812,115)	(3,856,145)	(4,393,519)	(3,337,461)	(2,259,475)	(2,241,503)	(864,250)	3,868,972
219	WACOG SUPPLY EXPENSE	9,799,549	7,644,572	7,215,364	6,183,787	5,191,831	5,162,836	5,379,653	97,845,905
220	WACOG VOLUMES	1,406,280	1,036,367	969,934	794,369	637,996	640,381	673,348	13,344,232
221	Average STORAGE W/D WACOG								

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	DESCRIPTION	AUG 2009	SEPT 2009	OCT 2009	NOV 2010	DEC 2010	JAN 2010	FEB 2010	MAR 2010
	DEMAND CHARGES								
222	TRANSCO SENTINEL FT				420,526	420,526	420,526	420,526	420,526
223	TRANSCO FT DEMAND STA 30	140,392	140,392	140,392	140,392	140,392	140,392	140,392	140,392
224	TRANSCO FT DEMAND STA 45	197,950	197,950	197,950	197,950	197,950	197,950	197,950	197,950
225	TRANSCO FT DEMAND STA 50	141,868	141,868	141,868	141,868	141,868	141,868	141,868	141,868
226	TRANSCO FT DEMAND STA 62	291,213	291,213	291,213	291,213	291,213	291,213	291,213	291,213
227	TRANSCO FT DEMAND WSS	1,930	1,930	1,930	1,930	1,930	1,930	1,930	1,930
228	G CAPACITY REL TRANSCO FT DEMAND STA 30	1,427	1,427	1,427	1,427	1,427	1,427	1,427	1,427
229	G CAPACITY REL TRANSCO FT DEMAND STA 45	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010
230	G CAPACITY REL TRANSCO FT DEMAND STA 50	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435
231	G CAPACITY REL TRANSCO FT DEMAND STA 62	2,949	2,949	2,949	2,949	2,949	2,949	2,949	2,949
232	TRANSCO PS-3 DEMAND STA 30	4,091	4,091	4,091	4,091	4,091	4,091	4,091	4,091
233	TRANSCO PS-3 DEMAND STA 45	5,807	5,807	5,807	5,807	5,807	5,807	5,807	5,807
234	TRANSCO PS-3 DEMAND STA 50	4,134	4,134	4,134	4,134	4,134	4,134	4,134	4,134
235	TRANSCO PS-3 DEMAND STA 62	8,492	8,492	8,492	8,492	8,492	8,492	8,492	8,492
236	TOTAL TRANSCO FT/PS-3 DEMAND CHARGES	803,697	803,697	803,697	1,224,223	1,224,223	1,224,223	1,224,223	1,224,223
237	TRANSP DEMAND CHARGE TRANSCO LEIDY LI	18,086	18,086	18,086	18,086	18,086	18,086	18,086	18,086
238									
239									
240									
241									
242	COLUMBIA FTS: DEMAND CHARGE	159,926	159,926	159,926	159,926	159,926	159,926	159,926	159,926
243	COLUMBIA SST: DEMAND CHARGE	46,165	46,165	46,165	92,330	92,330	92,330	92,330	92,330
244	COL GULF FTS-1: DEMAND CHARGE	61,812	61,812	61,812	61,812	61,812	61,812	61,812	61,812
245	COL GULF FTS-2: DEMAND CHARGE	6,905	6,905	6,905	6,905	6,905	6,905	6,905	6,905
246	COL PRODUCER CONTRACT DMD CHG	0	0	0	0	0	0	0	0
247	COLUMBIA SURCHARGES	0	0	0	0	0	0	0	0
248	TEXAS EASTERN ITP DEMAND	151,492	151,492	151,492	151,492	151,492	151,492	151,492	151,492
249	LATERAL DEMAND	0	0	0	0	0	0	0	0
250									
251	ESNG E-3 Surcharge	21,974	21,974	21,974	21,974	21,974	21,974	21,974	21,974
252	FT-365: ESNG DEMAND CHARGE	369,495	369,495	369,495	369,495	369,495	369,495	369,495	369,495
253	T-1: ESNG DEMAND CHARGE	5,520	5,520	5,520	5,522	5,522	5,522	5,522	5,522
254	ESNG SURCHARGES	0	0	0	0	0	0	0	0
255	NATIONAL FT DEMAND	16,513	16,513	16,513	16,513	16,513	16,513	16,513	16,513
256	Transportation Demand Credits/Refunds			0	0	0	0	0	0
257	SUBTOTAL FIRM DEMAND CHARGES	1,661,584	1,661,584	1,661,584	2,128,277	2,128,277	2,128,277	2,128,277	2,128,277
258	Storage Demand Credits/Refunds								
259	GSS: DEMAND CHARGE	88,343	88,343	88,343	88,343	88,343	88,343	88,343	88,343
260	CAPACITY CHARGE	35,616	35,616	35,616	35,616	35,616	35,616	35,616	35,616
261	WSS: DEMAND CHARGE	8,523	8,523	8,523	8,523	8,523	8,523	8,523	8,523
262	CAPACITY CHARGE	8,412	8,412	8,412	8,412	8,412	8,412	8,412	8,412
263	PYS: DEMAND CHARGE	17,758	17,758	17,758	17,758	17,758	17,758	17,758	17,758
264	CAPACITY CHARGE	8,580	8,580	8,580	8,580	8,580	8,580	8,580	8,580
265	LNG-peak: DEMAND CHARGE	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178
266	CAPACITY CHARGE	1,883	1,883	1,883	1,883	1,883	1,883	1,883	1,883
267	LG-A: DEMAND CHARGE	2,805	2,805	2,805	2,805	2,805	2,805	2,805	2,805
268	CAPACITY CHARGE	4,052	4,052	4,052	4,052	4,052	4,052	4,052	4,052
269	ESS: DEMAND CHARGE	11,589	11,589	11,589	11,589	11,589	11,589	11,589	11,589
270	CAPACITY CHARGE	11,584	11,584	11,584	11,584	11,584	11,584	11,584	11,584
271	FSS: DEMAND CHARGE	23,999	23,999	23,999	23,999	23,999	23,999	23,999	23,999
272	CAPACITY CHARGE	28,920	28,920	28,920	28,920	28,920	28,920	28,920	28,920
273	SUBTOTAL STORAGE DEMAND CHARGES	253,241	253,241	253,241	253,242	253,242	253,242	253,242	253,242

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	DESCRIPTION	APRIL 2010	MAY 2010	JUNE 2010	JULY 2010	AUG 2010	SEPT 2010	OCT 2010	Nov08-Oct09 GCR TOTAL
	DEMAND CHARGES								
222	TRANSCO SENTINEL FT	420,526	420,526	420,526	420,526	420,526	420,526	420,526	5,046,308
223	TRANSCO FT DEMAND STA 30	140,392	140,392	140,392	140,392	140,392	140,392	140,392	1,684,701
224	TRANSCO FT DEMAND STA 45	197,950	197,950	197,950	197,950	197,950	197,950	197,950	2,375,403
225	TRANSCO FT DEMAND STA 50	141,868	141,868	141,868	141,868	141,868	141,868	141,868	1,702,410
226	TRANSCO FT DEMAND STA 62	291,213	291,213	291,213	291,213	291,213	291,213	291,213	3,494,554
227	TRANSCO FT DEMAND WSS	1,930	1,930	1,930	1,930	1,930	1,930	1,930	23,155
228	G CAPACITY REL TRANSCO FT DEMAND STA 30	1,427	1,427	1,427	1,427	1,427	1,427	1,427	17,123
229	G CAPACITY REL TRANSCO FT DEMAND STA 45	2,010	2,010	2,010	2,010	2,010	2,010	2,010	24,123
230	G CAPACITY REL TRANSCO FT DEMAND STA 50	1,435	1,435	1,435	1,435	1,435	1,435	1,435	17,220
231	G CAPACITY REL TRANSCO FT DEMAND STA 62	2,949	2,949	2,949	2,949	2,949	2,949	2,949	35,388
232	TRANSCO PS-3 DEMAND STA 30	4,091	4,091	4,091	4,091	4,091	4,091	4,091	49,098
233	TRANSCO PS-3 DEMAND STA 45	5,807	5,807	5,807	5,807	5,807	5,807	5,807	69,687
234	TRANSCO PS-3 DEMAND STA 50	4,134	4,134	4,134	4,134	4,134	4,134	4,134	49,606
235	TRANSCO PS-3 DEMAND STA 62	8,492	8,492	8,492	8,492	8,492	8,492	8,492	101,898
236	TOTAL TRANSCO FT/PS-3 DEMAND CHARGES	1,224,223	1,224,223	1,224,223	1,224,223	1,224,223	1,224,223	1,224,223	14,690,674
237	TRANSP DEMAND CHARGE TRANSCO LEIDY LI	18,086	18,086	18,086	18,086	18,086	18,086	18,086	217,032
238									
239									
240									$0
241									
242	COLUMBIA FTS: DEMAND CHARGE	159,926	159,926	159,926	159,926	159,926	159,926	159,926	1,919,112
243	COLUMBIA SST: DEMAND CHARGE	92,330	46,165	46,165	46,165	46,165	46,165	46,165	830,970
244	COL GULF FTS-1: DEMAND CHARGE	61,812	61,812	61,812	61,812	61,812	61,812	61,812	741,744
245	COL GULF FTS-2: DEMAND CHARGE	6,905	6,905	6,905	6,905	6,905	6,905	6,905	82,860
246	COL PRODUCER CONTRACT DMD CHG	0	0	0	0	0	0	0	0
247	COLUMBIA SURCHARGES	0	0	0	0	0	0	0	0
248	TEXAS EASTERN ITP DEMAND	151,492	151,492	151,492	151,492	151,492	151,492	151,492	1,817,904
249	LATERAL DEMAND	0	0	0	0	0	0	0	0
250									
251	ESNG E-3 Surcharge	21,974	21,974	21,974	21,974	21,974	21,974	21,974	263,683
252	FT-365: ESNG DEMAND CHARGE	369,495	369,495	369,495	369,495	369,495	369,495	369,495	4,433,940
253	T-1: ESNG DEMAND CHARGE	5,522	5,522	5,522	5,522	5,522	5,522	5,522	66,264
254	ESNG SURCHARGES	0	0	0	0	0	0	0	0
255	NATIONAL FT DEMAND	16,513	16,513	16,513	16,513	16,513	16,513	16,513	198,152
256	Transportation Demand Credits/Refunds	0	0	0	0	0	0	0	0
257	SUBTOTAL FIRM DEMAND CHARGES	2,128,277	2,082,112	2,082,112	2,082,112	2,082,112	2,082,112	2,082,112	25,262,335
258	Storage Demand Credits/Refunds								
259	GSS: DEMAND CHARGE	88,343	88,343	88,343	88,343	88,343	88,343	88,343	1,060,116
260	CAPACITY CHARGE	35,616	35,616	35,616	35,616	35,616	35,616	35,616	427,392
261	WSS: DEMAND CHARGE	8,523	8,523	8,523	8,523	8,523	8,523	8,523	102,276
262	CAPACITY CHARGE	8,412	8,412	8,412	8,412	8,412	8,412	8,412	100,944
263	PYS: DEMAND CHARGE	17,758	17,758	17,758	17,758	17,758	17,758	17,758	213,096
264	CAPACITY CHARGE	8,580	8,580	8,580	8,580	8,580	8,580	8,580	102,960
265	LNG-peak: DEMAND CHARGE	1,178	1,178	1,178	1,178	1,178	1,178	1,178	14,136
266	CAPACITY CHARGE	1,883	1,883	1,883	1,883	1,883	1,883	1,883	22,596
267	LG-A: DEMAND CHARGE	2,805	2,805	2,805	2,805	2,805	2,805	2,805	33,660
268	CAPACITY CHARGE	4,052	4,052	4,052	4,052	4,052	4,052	4,052	48,624
269	ESS: DEMAND CHARGE	11,589	11,589	11,589	11,589	11,589	11,589	11,589	139,068
270	CAPACITY CHARGE	11,584	11,584	11,584	11,584	11,584	11,584	11,584	139,008
271	FSS: DEMAND CHARGE	23,999	23,999	23,999	23,999	23,999	23,999	23,999	287,988
272	CAPACITY CHARGE	28,920	28,920	28,920	28,920	28,920	28,920	28,920	347,040
273	SUBTOTAL STORAGE DEMAND CHARGES	253,242	253,242	253,242	253,242	253,242	253,242	253,242	3,038,904

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DELMARVA POWER & LIGHT COMPANY
OVERALL SUMMARY OF GAS COSTS
August 2007 - October 2008
15 Months Estimated

	DESCRIPTION	AUG 2009	SEPT 2009	OCT 2009	NOV 2010	DEC 2010	JAN 2010	FEB 2010	MAR 2010
	OVERALL SUMMARY								
287	FIRM DEMAND	316,253	322,617	552,060	1,447,314	2,333,674	2,552,551	2,136,871	1,681,152
288	NONFIRM DEMAND	0	0	0	0	0	0	0	0
289	STORAGE INJECTION (NO WSS)	446,042	411,900	320,216	0	0	0	0	0
290	WSS STORAGE INJ	0	0	0	0	0	0	0	0
291	TOTAL DEMAND	762,295	734,516	872,276	1,447,314	2,333,674	2,552,551	2,136,871	1,681,152
292	FIRM SUPPLY	694,579	668,248	806,008	1,224,411	1,655,376	1,538,415	1,411,203	1,356,152
293	NONFIRM SUPPLY	0	0	0	0	0	0	0	0
293	WSS & ESS WITHDRAWAL	20,688	20,688	20,688	0	0	100,000	100,000	40,000
294	STORAGE WITHDRAWAL (less WSS & ESS)	47,028	45,580	45,580	222,903	678,298	914,136	625,668	285,000
294	TOTAL SUPPLY	762,295	734,516	872,276	1,447,314	2,333,674	2,552,551	2,136,871	1,681,152
295	**NET SUPPLY VS DEMAND**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	COMMODITY EXPENSE, $								
296	TOTAL COMMODITY FIRM TRANSPORT $	5,378,708	6,603,823	6,379,495	8,688,741	11,462,573	11,223,246	10,268,931	9,625,323
297	TOTAL COMMODITY NONFIRM TRANSPORT $	0	0	0	0	0	0	0	0
298	SUBTOTAL COMMODITY STORAGES $	(2,817,532)	(2,546,283)	(1,183,911)	1,498,553	5,493,706	8,366,272	6,012,207	3,262,703
299	TOTAL COMMODITY $	2,561,176	4,057,540	5,195,584	10,187,294	16,956,279	19,589,518	16,281,138	12,888,026
	DEMAND EXPENSE, $								
300	SUBTOTAL DEMAND FIRM TRANSPORT	1,661,584	1,661,584	1,661,584	2,128,277	2,128,277	2,128,277	2,128,277	2,128,277
301	SUBTOTAL DEMAND STORAGES	253,241	253,241	253,241	253,242	253,242	253,242	253,242	253,242
302	TOTAL DEMAND	1,914,826	1,914,826	1,914,826	2,381,519	2,381,519	2,381,519	2,381,519	2,381,519
	TOTAL EXPENSE $								
303	TOTAL FIRM TRANSPORT	7,040,292	8,265,408	8,041,080	10,817,018	13,590,850	13,351,523	12,397,208	11,753,600
304	TOTAL STORAGE CHARGES	(2,564,291)	(2,293,042)	(930,670)	1,751,795	5,746,948	8,619,514	6,265,449	3,515,945
305	PRIOR PERIOD ADJUSTMENTS	0	0	0	0	0	0	0	0
306	TOTAL GAS SUPPLY EXPENSE $	4,476,002	5,972,366	7,110,410	12,568,813	19,337,798	21,971,037	18,662,657	15,269,545
307									
308									
309	**WACCOG, $/MCF**	**8.0985**	**12.5770**	**9.4113**	**7.0388**	**7.2659**	**7.6745**	**7.6191**	**7.6662**

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DELMARVA POWER & LIGHT COMPANY
OVERALL SUMMARY OF GAS COSTS
August 2007 - October 2008
15 Months Estimated

	DESCRIPTION	APRIL 2010	MAY 2010	JUNE 2010	JULY 2010	AUG 2010	SEPT 2010	OCT 2010	Nov08-Oct09 GCR TOTAL
	OVERALL SUMMARY								
287	FIRM DEMAND	865,320	487,782	350,691	321,306	316,253	322,617	552,060	13,367,591
288	NONFIRM DEMAND	0	0	0	0	0	0	0	0
289	STORAGE INJECTION (NO WSS)	545,959	553,585	624,243	478,063	328,190	322,764	126,288	2,979,092
290	WSS STORAGE INJ	0	0	0	0	0	0	0	0
291	TOTAL DEMAND	1,411,280	1,041,367	974,934	799,369	644,444	645,381	678,348	16,346,685
292	FIRM SUPPLY	1,406,280	1,036,367	969,934	794,369	637,996	640,381	673,348	13,344,232
293	NONFIRM SUPPLY	0	0	0	0	0	0	0	0
293	WSS & ESS WITHDRAWAL	0	0	0	0	0	0	0	240,000
294	STORAGE WITHDRAWAL (less WSS & ESS)	5,000	5,000	5,000	5,000	6,448	5,000	5,000	2,762,453
294	TOTAL SUPPLY	1,411,280	1,041,367	974,934	799,369	644,444	645,381	678,348	16,346,685
295	**NET SUPPLY VS DEMAND**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
							0		
	COMMODITY EXPENSE, $								
296	TOTAL COMMODITY FIRM TRANSPORT $	9,799,549	7,644,572	7,215,364	6,183,787	5,191,331	5,162,836	5,379,653	**97,845,905**
297	TOTAL COMMODITY NONFIRM TRANSPORT $	0	0	0	0	0	0	0	**0**
298	SUBTOTAL COMMODITY STORAGES $	(3,812,115)	(3,856,145)	(4,393,519)	(3,337,461)	(2,259,475)	(2,241,503)	(864,250)	**3,868,972**
299	TOTAL COMMODITY $	5,987,434	3,788,427	2,821,845	2,846,326	2,931,856	2,921,333	4,515,403	**101,714,877**
	DEMAND EXPENSE, $								
300	SUBTOTAL DEMAND FIRM TRANSPORT	2,128,277	2,082,112	2,082,112	2,082,112	2,082,112	2,082,112	2,082,112	**25,262,335**
301	SUBTOTAL DEMAND STORAGES	253,242	253,242	253,242	253,242	253,242	253,242	253,242	**3,038,904**
302	TOTAL DEMAND	2,381,519	2,335,354	2,335,354	2,335,354	2,335,354	2,335,354	2,335,354	**28,301,239**
	TOTAL EXPENSE $								
303	TOTAL FIRM TRANSPORT	11,927,826	9,726,684	9,297,476	8,265,899	7,273,443	7,244,948	7,461,765	**123,108,240**
304	TOTAL STORAGE CHARGES	(3,558,873)	(3,602,903)	(4,140,277)	(3,084,219)	(2,006,233)	(1,988,261)	(611,008)	**6,907,876**
305	PRIOR PERIOD ADJUSTMENTS	0	0	0	0	0	0	0	**0**
306	TOTAL GAS SUPPLY EXPENSE $	8,368,953	6,123,781	5,157,199	5,181,680	5,267,210	5,256,687	6,850,757	**130,016,116**
307									176,508,744
308									46,492,628
309	**WACCOG, $/MCF**	**6.9193**	**7.7666**	**8.0465**	**8.8586**	**9.2706**	**9.0551**	**8.1792**	**7.6091**

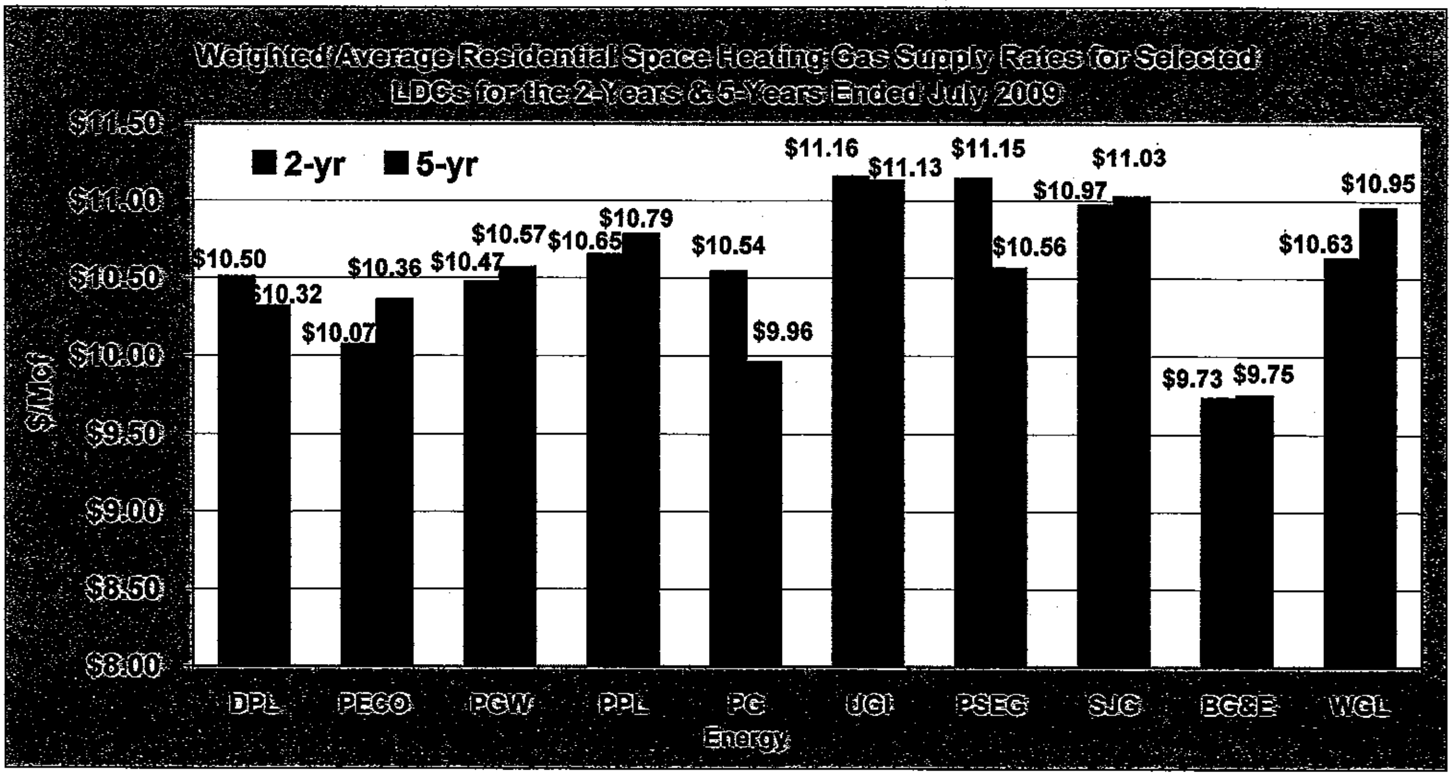
Delmarva Power
Summary of Natural Gas Commodity Cost Volatility

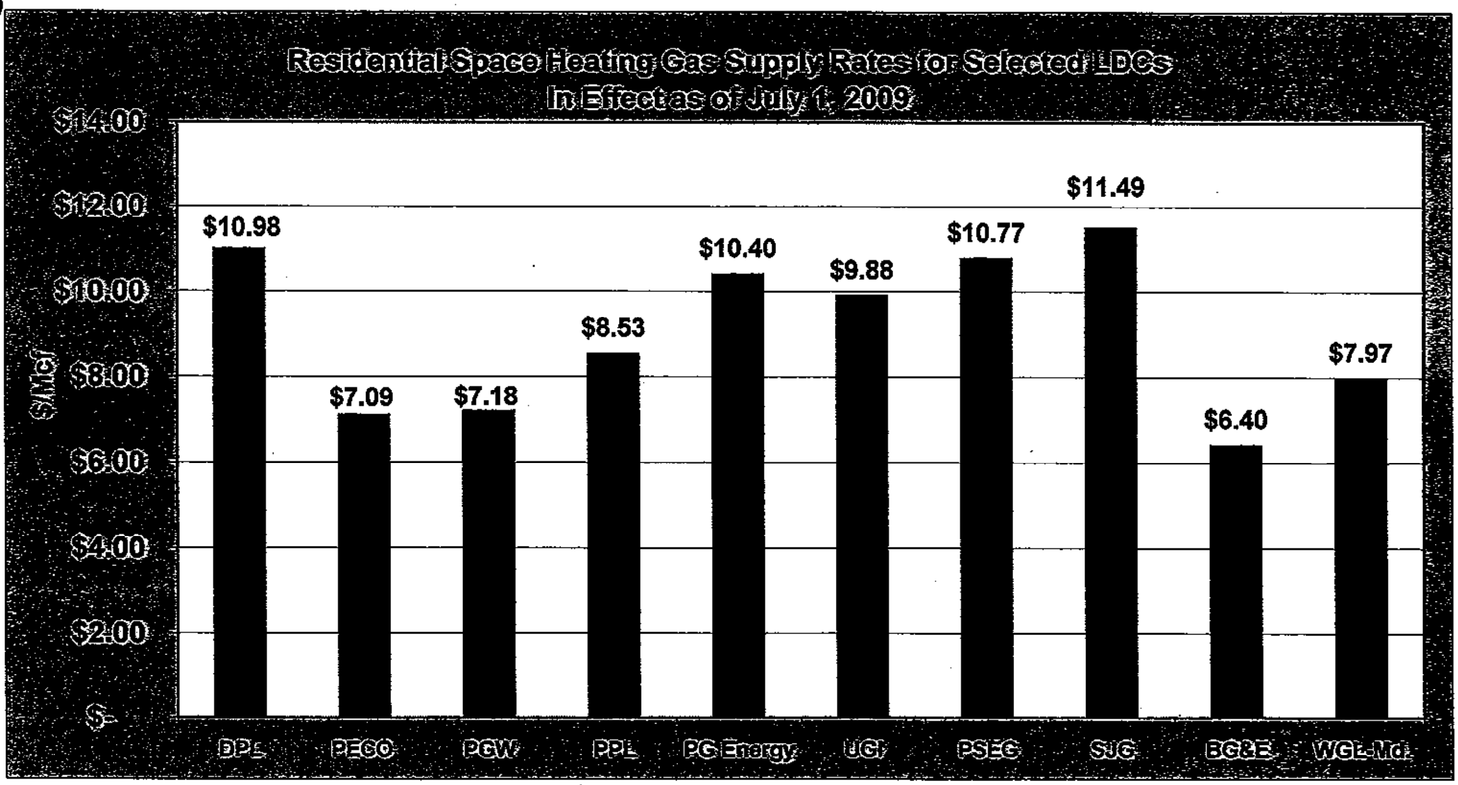
	Standard Deviation	(1) Hedge Wacog	(2) WACCOG	(3) NYMEX LDS
1	Nov05-Oct06	1.12	1.47	2.76
2	Nov06-Oct07	0.41	1.10	0.85
3	Nov07-Oct08	0.44	1.64	1.92
4	Nov08-June09	0.27	1.05	1.36

	Average Deviation	(1) Hedge Wacog	(2) WACCOG	(3) NYMEX LDS
1	Nov05-Oct06	0.99	1.08	2.13
2	Nov06-Oct07	0.35	0.82	0.67
3	Nov07-Oct08	0.38	0.38	1.58
4	Nov08-June09	0.23	0.23	1.26

Delmarva Power
Hedge Costs Compared to WACCOG & NYMEX Gas Futures Prices
(dollar per MMBtu)

	(1)	(2)		(3)		(4)		(5)	
	Time Period	Hedge Wacog		WACCOG		18-Months Prior Ave NYMEX		12-Months Prior Ave NYMEX	
1	Nov05-Oct06	$	8.90	$	8.21	$	8.27	$	8.98
2	Nov06-Oct07	$	7.58	$	7.84	$	8.86	$	8.53
3	Nov07-Oct08	$	8.37	$	7.68	$	8.73	$	8.75
4	Nov08-June09	$	8.95	$	8.59	$	8.71	$	8.69


Weighted Average Residential Space Heating Gas Supply Rates for Selected LDCs for the 2-Years & 5-Years Ended July 2009
2-yr
5-yr
$/Mcf
$11.50
$11.00
$10.50
$10.00
$9.50
$9.00
$8.50
$8.00
$10.50
$10.32
$10.07
$10.36
$10.47
$10.57
$10.65
$10.79
$10.54
$9.96
$11.16
$11.13
$11.15
$10.56
$10.97
$11.03
$9.73
$9.75
$10.63
$10.95
DPL
PECO
PGW
PPL
PG Energy
UGI
PSEG
SJG
BG&E
WGL


Residential Space Heating Gas Supply Rates for Selected LDCs In Effect as of July 1, 2009
$/Mcf
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
$10.98
$7.09
$7.18
$8.53
$10.40
$9.88
$10.77
$11.49
$6.40
$7.97
DPL
PECO
PGW
PPL
PG Energy
UGI
PSEG
SJG
BG&E
WGL-Md.

Delmarva Power
Considerations When Entering Into Hedge Transaction

1) Current market prices are relatively high or low compared to historical prices
2) Current market prices are lower than those inherent in the currently effective GCR
3) Hedging for winter, summer or hurricane season
4) EIA Storage Reports
5) Weather Forecasts
6) Winter or Summer Season
7) Risk of Hurricanes
8) EIA and PIRA fundamental wholesale gas price forecasts
9) Market Price movements within the month
10) Rig Counts
11) Imports - Canada & LNG
12) Economic Activity

Note: Considerations listed above are not in order of Importance

Delmarva Power
Summary of Gas Hedges Entered Into During 2008

	Citygate Delivery Portfolio						Storage Portfolio					
	No.	Date	Transaction Type	Rates	Daily Volume	Hedge Term	No.	Date	Transaction Type	Rates	Daily Volume	Hedge Term
First Quarter 2008	1	3/17/2008	Swap	$ 8.620	2,500	Apr09-Oct09	45	2/21/2008	Swap	$ 8.43	2,500	Apr09-Oct09
1st Qtr = 2												
Second Quarter 2008	2	4/2/2008	Swap	$ 9.450	10,000	Nov08-Mar09	46	4/29/2008	Swing Swap	$10.71	2,500	May 08 only
	3	6/26/2008	Swap	$ 12.960	2,500	Oct08 Only	47	5/29/2008	Swing Swap	$11.35	2,500	June 1-30
4th Qtr = 6	4	6/26/2008	Swap	$ 12.950	2,500	Oct08 Only						
	5	6/26/2008	Swap	$ 13.180	2,500	Nov08 Only						
Third Quarter 2008	6	7/2/2008	Swap	$ 11.930	2,500	April 09 only	48	7/14/2008	Swing Swap	$11.77	2,500	July 15-31 only
	7	7/3/2008	Swap	$ 11.780	2,500	April 09 only	49	7/15/2008	Swing Swap	$11.48	2,500	July 16-31 only
	8	7/7/2008	Futures	$ 11.740	2,333	April 09 only	50	10/6/2008	Swap	$ 6.95	2,500	Nov08 only
	9	7/7/2008	Futures	$ 11.750	2,333	April 09 only						
2nd Qtr = 31	10	7/8/2008	Swap	$ 12.837	2,500	Oct 08 only						
	11	7/8/2008	Swap	$ 13.118	2,500	Nov 08 only						
	12	7/8/2008	Swap	$ 13.150	2,500	Nov08-Mar09						
	13	7/9/2008	Swap	$ 11.135	2,500	Apl09-Oct09						
	14	7/9/2008	Swap	$ 10.150	2,500	Apl10-Oct10						
	15	7/15/2008	Swap	$ 11.350	2,500	Cal 2009						
	16	7/17/2008	Swap	$ 11.390	2,500	Nov08-Mar09						
	17	7/22/2008	Swap	$ 10.980	2,500	Nov08-Mar09						
	18	7/24/2008	Swap	$ 9.570	2,500	Cal 2009						
	19	7/24/2008	Swap	$ 9.990	2,500	Nov08-Mar09						
	20	8/4/2008	Swing Swap	$ 8.980	2,500	Aug 5-31 only						
	21	8/4/2008	Swing Swap	$ 8.890	2,500	Aug 5-31 only						
	22	8/4/2008	Swing Swap	$ 8.690	2,500	Aug 5-31 only						
	23	8/7/2008	Swap	$ 9.490	2,500	Nov08-Mar09						
	24	8/9/2008	Swap	$ 9.120	2,500	Nov08-Mar09						
	25	8/12/2008	Swap	$ 8.280	2,500	Sept08 only						
	26	8/15/2008	Swap	$ 8.980	2,500	Cal 2009						
	27	8/22/2008	Swap	$ 7.910	2,500	Oct08 only						
	28	8/28/2008	Swing Swap	$ 7.980	2,500	Sept08 only						
	29	8/28/2008	Swing Swap	$ 8.386	2,500	Sept08 only						
	30	8/28/2008	Swap	$ 8.708	2,500	Oct08 only						
	31	9/3/2008	Swap	$ 8.070	2,500	Dec08only						
	32	9/4/2008	Swap	$ 7.570	2,500	Nov08only						
	33	9/4/2008	Swap	$ 8.270	2,500	Jan09only						
Fourth Quarter 2008	34	10/15/2008	Swap	$ 7.870	2,500	Cal 2010	51	12/23/2008	Swap	$ 6.68	2,500	April-Oct 2010
	35	10/23/2008	Swap	$ 7.690	2,500	Cal 2010						
	36	10/28/2008	Swap	$ 6.370	2,500	Dec08 only						
4th Qtr = 12	37	10/28/2008	Swap	$ 6.365	2,500	Dec08 only						
	38	10/28/2008	Swap	$ 6.670	2,500	Jan09 only						
	39	10/28/2008	Swap	$ 6.655	2,500	Jan09 only						
	40	10/28/2008	Swap	$ 6.722	2,500	Feb09 only						
	41	10/28/2008	Swap	$ 6.680	2,500	Feb09 only						
	42	11/11/2008	Swap	$ 8.090	2,500	Cal 2011						
	43	11/12/2008	Swap	$ 6.750	2,500	Feb09 only						
	44	12/23/2008	Swap	$ 7.090	2,500	Cal 2010						

C. RONALD McGINNIS JR.

DELMARVA POWER & LIGHT COMPANY

TESTIMONY OF C. RONALD MCGINNIS, JR.

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

CONCERNING THE NOVEMBER 2009 THROUGH OCTOBER 2010

GAS COST RATE

PSC DOCKET NO. 09-____F

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1. Q: <u>State your name, position, and business address.</u>

A: C. Ronald McGinnis, Jr., Regulatory Team Lead, Regulatory Affairs Department, for PHI Service Company, which is a subsidiary of Pepco Holdings, Inc., the parent company of Delmarva Power & Light Company ("the Company" or "Delmarva"), New Castle Regional Office, 401 Eagle Run Road, Newark, Delaware 19714.

2. Q: <u>Please state your educational background and relevant experience.</u>

A: I graduated from the University of Delaware with a Bachelor of Science degree in Accounting and earned a Masters in Business Administration degree with a concentration in Finance from Widener University. In 1992, I became an employee of Delmarva Power & Light Company. My responsibilities now include, among other things, the calculation and monitoring of jurisdictional fuel revenue and expenses for Delmarva Power. Prior to joining Delmarva, I was employed as a Rate of Return Analyst by AUS Consultants and as a Senior Accountant by Wilmington Savings Fund Society.

3. Q: **<u>Have you previously testified before this Commission?</u>**

A: Yes, I have testified before this Commission in ten of the previous thirteen GCR Dockets and in the Electric Restructuring Docket No. 99-163.

4. Q: **<u>What is the purpose of this testimony?</u>**

A: The Company is seeking approval of a decrease to the Gas Cost Rate ("GCR") to be effective with usage on and after November 1, 2009, with proration. This testimony supports the calculation of the proposed GCR, as summarized on Schedule CRM-1, Page 1. Schedules CRM-1, page 2 through CRM-11 provide details used in the development of the proposed GCR factors and selected comparative data, including a reconciliation of firm gas expenses and revenues for the twelve months ended July 31, 2009. Calculation of the proposed GCR factors is based on the gas sales forecast sponsored by Witness Phillips, and the delivered cost of purchased gas, the average pipeline rate, and system design day load, sponsored by Witness Bacon, and the Large Volume Gas (LVG) and Medium Volume Gas (MVG) customer Maximum Daily Quantities ("MDQ").

My testimony specifically addresses the following matters:

1. The reconciliation of actual versus estimated system weighted average commodity cost of gas ("WACCOG") assigned to LVG and electing MVG Customers;
2. The audit of the GCR for calendar year 2008; and
3. Adjustments contained in the actual data for the 12 months ended on July 31, 2009.

5. Q: **Please compare the proposed 2009/2010 GCR to the current rate.**

A: The proposed GCR components applicable to firm sales customers, compared with the currently effective Gas Cost Rate factors, are shown below:

GAS COST RATE

	Current	Proposed	Change
RG, GG, and GL	109.812¢/ccf	93.959¢/ccf	(15.853)¢/ccf
LVG and MVG Demand	$8.5538/Mcf of MDQ*	$9.5152/Mcf of MDQ*	$0.9614/Mcf of MDQ*
Non-Electing MVG Commodity	$9.7555/Mcf	$7.9076/Mcf	$(1.8479)/Mcf
LVG and Electing MVG Commodity	Varies Monthly	Varies Monthly	N/A

- "MDQ" is Maximum Daily Quantity, which is a measure of a customer's contribution to peak demand.

The 2009/2010 GCR factors are summarized on Schedule CRM-1, Page 1 of 6. Calculations which support the Commodity Cost Rate (CCR) factors appear on Schedule CRM-1, Pages 2 and 3. Derivation of the Demand Cost Rate (DCR) factors for LVG/MVG customers and Volumetric customers is shown on Schedule CRM-1, Pages 4 through 6. The details of the calculation of Off-System Sales and Capacity Release Margins are itemized on Schedule CRM-2. Schedule CRM-3 shows the allocation of estimated costs between the various customer classes, and Schedule CRM-4 includes the derivation of the Demand Expense True-up for the prior GCR period. Schedules CRM-5 and 7, and CRM-11 contain the Recovery Schedules and the associated interest calculations. Schedule CRM-8 shows the derivation of the LVG and Electing MVG WACCOG true-up for July 2008 through June 2009. Schedules CRM-9 and CRM-10 contain comparisons of sales and recoverable fuel costs.

The presently effective DCR factor applicable to MVG and LVG customers and the current CCR and DCR factors applicable to RG and GG customers were approved by Commission Order No. 7532 in Docket No. 08-266F, and were effective with usage on and after March 1, 2009, with proration. There is now a projected under-recovery, based on updated estimates, of $3.3 million, or 2.1%, as of October 31, 2009 which has been included in the calculation of the 2009/2010 GCR.

6. Q: <u>Please explain the derivation of the estimated firm gas expenses for the period November 2009 through October 2010.</u>

A: The total estimated gas expenses for the upcoming GCR period are sponsored by Witness Bacon in his Schedule WTB-5. Estimated gas costs associated with Company-Use are credited against total estimated gas commodity costs in their entirety. Revenue from Transition Charges from customers who switched from a Firm Sales to a Transportation Service, No-Notice Swing Charges, and Balancing Charges are all credited against estimated gas demand expenses at 100% of their value. Margins related to Interruptible Transportation are shared with customers on an 80% / 20% basis with 80% returned to the Firm customer through revenue credits and 20% retained as Company gross profit.

Margins from Capacity Release, Off-System Sales and Swaps were credited to the GCR at 100% until a total credit of $1.7 million for the 12-month period ending every June. Once the $1.7 million threshold was met, the margins were then shared at the 80% level until the following July, when the cycle began again. Provision G of the Proposed Settlement Agreement in Docket No. 08-266F would raise the $1.7 million threshold was raised to $3.0 million. The $3.0 million threshold was used in the derivation of the proposed GCR.

7. Q: **<u>Please explain how the revenue credits for service to Interruptible Gas Transportation customers were developed.</u>**

A: Margins associated with the fourteen (as of July 31) Interruptible Gas Transportation customers are shared on an 80%/20% basis, with 80% credited to firm full-requirements customers through development of the Demand Factor of the GCR. These margins include customer charges and delivery charges incurred by those customers.

8. Q: **<u>Please discuss the gas costs and recoveries for the current November 2008 through October 2009 GCR period.</u>**

A: The monthly comparison of actual gas cost and recovery for the period November 2008 through July 2009 and estimated gas cost and recovery for the period August 2009 through October 2009 are shown in Schedule CRM-6, Pages 1 and 2. Firm gas costs and recoveries have been compared for each of those months to determine the monthly over or under-recovery of gas costs.

Schedule CRM-6, Page 1 shows the projected under-recovery balance of $3,256,259 or 2.1% of estimated recoverable gas expenses, which is based on nine months of historical data and three months of updated estimates prepared for this filing. This is within the 6.0% deadband for under-recoveries which would require a supplemental GCR filing.

Pages 3 and 4 of Schedule CRM-6 contain the actual results for the 2007/2008 GCR period.

These comparisons, along with other required information, have been filed on a monthly basis with the Commission.

9. Q: **<u>Please discuss the interest calculation.</u>**

A: As specified on Leaf No. 36 in the Company's Gas Service Tariff, interest in the amount of $15,815 was calculated based on the average monthly gas deferred fuel balances, at the rate of 1/12 of the applicable FERC Natural Gas Interest Rate

Factor, which is available on the FERC website. The interest calculation for the 2008/2009 GCR period is based nine months of historical data and three months of updated estimates prepared for this filing, and is detailed on Schedule CRM-7.

10. Q: <u>Please describe the derivation of the proposed Commodity Cost Rate factors for the 2009/2010 GCR period.</u>

A: Two steps derive the Commodity Cost Rate ("CCR") factors for the Company's Firm customers. First, total estimated firm commodity costs are allocated between Annual CCR (RG, GG, GL, and Non-Electing MVG customers) and Monthly CCR (LVG and Electing MVG) customers. I have followed the same methodology used in prior GCR filings to calculate estimated commodity costs to be assigned to the Monthly CCR customers by setting the commodity portion each month at the system Weighted Average Commodity Cost of Gas ("WACCOG") projected for that month (as adjusted for losses and unaccounted-for gas). This sets monthly commodity revenues equal to expenses for Monthly CCR customers. Schedule CRM-1, Page 3 details the calculation of these assigned costs and revenues. All remaining estimated firm commodity expenses are assigned to the Annual CCR customers.

A true-up of LVG and Electing MVG commodity revenues and expenses will be made if there is an over-recovery or under-recovery that exceeds 5% of total gas commodity costs or $250,000 for the 12 months ended June 30, 2009. The actual WACCOG variance for the 12 months ended June 30, 2009 was an over-recovery of $38,734 or 1.00% as shown on CRM-8. Therefore, there is no true-up required for the 2009/2010 GCR period

Once the assignment of estimated firm commodity costs between Annual and Monthly CCR customers has been made, the Annual CCR factor can be calculated. Any over- recovery or under-recovery balance and associated interest remaining from the prior GCR period, net of the demand cost true-up discussed in response to

Question No. 13, is assigned to the Annual CCR customers. The calculation of commodity gas cost factors is shown on Schedule CRM-1, Page 2.

11. Q: <u>There is an adjustment made for "Proration of November 2008 GCR" on Schedule CRM-1, Page 2. What is the reason for this adjustment and how was it calculated?</u>

A: Customer bills are "prorated" each November so that the number of days on the bill that relate to October usage are charged the rate that was in effect during that month and the number of days that relate to November usage are charged the rate proposed in this filing. Since meters are read throughout the month (there are 21 billing cycles) this will affect the majority of customers who receive an annualized commodity rate. When estimating the over/under recovery of fuel expense for each November, a half-month convention is used so that when determining November revenue, 50% of sales have the prior period GCR applied to them, and the other 50% of sales are valued using the proposed GCR.

GCR filings prior to 2007/2008 have had estimates of November fuel revenue based upon the application of the proposed rate to estimated sales for the entire month. This creates a built-in error which over-estimates fuel revenue when the GCR is increasing and under-estimates fuel revenue when the GCR is decreasing. The Proration Adjustment reduces the potential proration error and synchronizes the November rates and estimated revenue with the way that actual fuel revenue is reported on the Company's books and records.

12. Q: <u>Please describe the derivation of the proposed Demand Cost Rate factors for the 2009/2010 GCR period.</u>

A: Demand-related costs are allocated and recovered through two separate and distinct mechanisms in accordance with past practices. The allocation of firm gas demand charges is the first step in this process, and involves the calculation of average and excess daily loads. Average daily loads are calculated by dividing projected sales over the entire GCR period, by class, by the number of days in the period (365 for the purpose of this filing). These average daily loads are then multiplied by the Average Pipeline Rate, sponsored by Witness Bacon, to derive firm demand expenses attributable to service rendered to support average loads. All remaining firm demand expenses are allocated based on excess loads, which are calculated by subtracting the average daily loads, by class, from the design day loads. The ratio of each class' excess load to the system total is then multiplied by the demand costs which remain unallocated after the development of expenses based on average loads. The addition of the average and excess load allocations result in the firm demand costs which are to be collected from the volumetric (RG, GG, and GL) and Demand Metered (MVG and LVG) classes.

The gas demand rate applicable to MVG and LVG customers is calculated by dividing their share of firm demand charges by their total Contract Maximum Daily Quantity ("MDQ"), which is a measure of an individual customer's contribution to the peak level of demand. This calculation appears on Schedule CRM-1, Page 4.

Firm gas demand expenses not allocated to the non-volumetric DCR customers are the basis for calculating the volumetric DCR factor. The calculation of the volumetric DCR factor appears on Schedule CRM-1, Page 6.

A summary of the allocation of firm commodity and demand expenses among the various classes is shown on Schedule CRM-3, Page 1.

13. Q: <u>Please discuss the demand cost true-up included in the calculation of the Demand Cost Rate factors for both volumetric and non-volumetric customers.</u>

A: A true up of demand-related cost differences has been applied to all sales customers. This true up is achieved by comparison of the estimated monthly demand costs and the actual demand costs for the period August 2008 through July 2009. For the period August 2009 through October 2009, estimates from the

October 1, 2008 GCR filing are compared to the estimates developed for use in this filing. The cumulative monthly variance is multiplied by 1/12 of the FERC Gas Refund Rate interest rate then in effect. The total true up (variance plus interest) of $608,230 is allocated among the volumetric and non-volumetric customers in the development of the volumetric and non-volumetric DCR factor calculations.

14. Q: <u>Please describe Schedules CRM-9 through CRM-11.</u>

A: Schedule CRM-9 details actual and estimated monthly sales for the twelve months ended October 31 in 2008, 2009, and 2010. Schedule CRM-10 compares the actual and estimated gas costs and regulatory credits for the twelve months ended October 31 in 2008, 2009, and 2010. Schedule CRM-11 provides the actual recovery results for the twelve-month reconciliation period ended July 31, 2009.

15. Q: <u>Please describe the calendar year 2008 GCR audit.</u>

A: During the 1996/1997 GCR proceeding in Docket No. 96-218F, the parties agreed that Delmarva's Internal Audit Department should expand the scope of its annual GCR audit, in light of the various rate design changes and margin sharing mechanisms approved by the Commission in Docket No. 95-44, which were implemented effective April 1, 1996. The principal concern focused on determining that customer billing and the determination and sharing of margins were treated in accordance with the Commission's Order and Delmarva's tariff.

The Company's Internal Auditing Department is in the process of completing the audit for calendar year 2008, which includes the review of a sampling of customer billing and regulatory accounting records concerning sales, gas costs, and gas cost revenue. The audit procedures and results will be reviewed by Price-Waterhouse-Coopers LLC for the purpose of forming an opinion on the basic financial statements, taken as a whole. The final audit report concerning the

GCR in 2008 is scheduled to be completed and filed with the Commission before the end of October 2009.

16. Q: <u>Please discuss any significant accounting adjustments to be made in the remaining months of the 2008/2009 GCR Period.</u>

A: There will be a $1.45 million adjustment made to commodity expenses in August 2009. The adjustment is to correct for an over-statement of costs resulting from the transfer of storage transactions from spreadsheets to the *Infinite* system in July 2009. This adjustment has been included in the projected demand costs for August 2009 in this filing.

17. Q: <u>Please summarize the calculation of the GCR factors proposed for the 12-month period beginning November 1, 2009.</u>

A: The proposed GCR factors applicable to volumetric customers for the 2009/2010 GCR period is based on the following amounts:

	Commodity	Demand	Total
• Estimated Firm Gas Costs for the 2009/2010 GCR period	$101,620,488	$18,873,426	$120,493,914
• Estimated Under-Recovery Position at 10/31/08	3,256,259	N/A	3,256,259
• True-Ups and Timing Differences	(1,354,978)	608,230	(746,749)
• Net Interest Amount	15,815	N/A	15,815
Subtotal	$103,537,584	$19,481,656	$123,019,240
• Monthly CCR Factor Credit	(1,581,802)	N/A	(1,581,802)
• MVG/LVG DCR Factor Credit	N/A	(909,576)	(909,576)
Volumetric Expenses	$101,955,782	$18,572,080	$120,527,862
• Estimated 2009/2010 GCR Period Sales	12,893,317	12,478,672	N/M
Volumetric Gas Cost Rate	$7.9076/Mcf	$1.4883/Mcf	$9.3959/Mcf

18. Q: <u>What would be the effect of this proposed GCR on customers' bills?</u>

A: The effect of this proposed decrease to the GCR on a residential space heating customer using 120 ccf in a winter month would be a decrease of $19.02, or 10.2%, from $186.32 to $167.30, summarized as follows:

Particulars	Base Rates and Current GCR	Base Rates and Proposed GCR
Base Rate Billing	$54.55	$54.55
GCR	131.77	112.75
Total Bill Amount	$186.32	$167.30
$ Decrease		$19.02
% Decrease		10.2%

Gas costs included in the proposed GCR represent approximately 67% of the total bill amount under the proposed GCR. General Gas ("GG") and non-electing MVG customers would experience a decrease in the commodity portion of their bill in the range of 6.2% to 16.1% depending on consumption characteristics and Service Classification.

19. Q: <u>Please describe the tariff revisions proposed by Delmarva in this filing.</u>

A: Attached as Schedule CRM-12 are the following P.S.C. Del. No. 5 - Gas tariff leafs, red-lined-up to show the modifications proposed by the Company:

- 42nd revised Leaf No. 37
- 38th Revised Leaf No. 38
- 21st Revised Leaf No. 39

"Clean" revised tariff leafs are appended to the Application as Appendix A.

20. Q: <u>Does this conclude your pre-filed direct testimony?</u>

A: Yes, it does.

Delmarva Power & Light Company
Summary of Gas Cost Rate
Commodity and Demand Factors
For November 2009 Through October 2010

Description	RG, GG, and GL	Non-Electing MVG	Electing MVG	LVG
Commodity	$7.9076 / Mcf	$7.9076 / Mcf	Varies	Varies
Demand	$1.4883 / Mcf	$9.5152 / Mcf of MDQ	$9.5152 / Mcf of MDQ	$9.5152 / Mcf of MDQ
Total GCR	$9.3959 / Mcf			

Delmarva Power & Light Company
Calculation of Gas Cost Rate Commodity Factors
For November 2009 Through October 2010

Description	RG, GG, GL and Non Electing MVG ($)	Electing MVG ($)		LVG ($)		Total ($)
Estimated Over-Recovery Position @ October 31, 2009	3,256,259	0		0		3,256,259
Interest Income	15,815	0		0		15,815
Estimated Recovery Position @ November 1, 2009	3,272,074	0		0		3,272,074
Demand Expense True-Up (1)	(608,230)					(608,230)
FPS Commodity True-Up	0					0
Proration of November 2009 GCR (2)	(746,749)					(746,749)
Total Estimated Firm Commodity Costs	100,038,686	243,171		1,338,631		101,620,488
Total Commodity Revenues to be Collected	101,955,782	243,171		1,338,631		103,537,584
Estimated Firm Sales	12,893,317	30,000		172,026		13,095,343
Commodity Cost Factor	7.9076	Varies	(4)	Varies	(4)	N / M

N /M = Not Meaningful

Notes:
(1) See Schedule CRM-4 for Demand Expense True-Up calculation.
(2) November 2009 revenue from RG, GG, GL, and MVG is prorated between old and new GCR, which corrects for a revenue deficit when rates are rising and a revenue surplus when rates are falling. The adjustment is calculated as follows:

	One Half of November 2009 Sales	Proposed Rate	Current Rate	Difference	Adjustment
RR, RSH, GG, GL	452,901	$9.3959	$10.9812	($1.5853)	($717,984)
Non Electing MVG Commodity	15,566	$7.9076	$9.7555	($1.8479)	($28,764)
Total	468,467				($746,749)

(4) The commodity gas cost for electing MVG and LVG Customers is the monthly system Weighted Average Commodity Cost of Gas (WACCOG), adjusted for losses at 2.0% and any WACCOG true-up from the prior period, and is shown on Page 3 of this Schedule.

Delmarva Power & Light Company
Monthly MVG and LVG Commodity Cost Factor Revenues
August 2009 Through October 2010
(15 Months Estimated)

Description	System WACCOG	Commodity Rate (1)	LVG Sales	LVG Revenue	Electing MVG Sales	Electing MVG Revenue	Total Monthly CCR Revenue
	($/Mcf)	($/Mcf)	(Mcf)	($)	(Mcf)	($)	
August 2009	9.4335	9.6222	5,006	48,169	2,500	24,056	72,225
September	9.6051	9.7972	4,618	45,243	2,500	24,493	69,736
October 2009	9.4113	9.5995	3,320	31,870	2,500	23,999	55,869
November 2009	7.0388	7.1796	7,266	52,167	2,500	17,949	70,116
December 2009	7.2659	7.4112	20,038	148,506	2,500	18,528	167,034
January 2010	7.6745	7.8280	28,246	221,110	2,500	19,570	240,680
February	7.6191	7.7715	32,390	251,719	2,500	19,429	271,148
March	7.6662	7.8195	26,481	207,068	2,500	19,549	226,617
April	6.9193	7.0577	22,658	159,913	2,500	17,644	177,557
May	7.7666	7.9219	13,713	108,633	2,500	19,805	128,438
June	8.0465	8.2074	3,718	30,515	2,500	20,519	51,034
July	8.8586	9.0358	4,572	41,312	2,500	22,590	63,902
August	9.2706	9.4560	5,006	47,337	2,500	23,640	70,977
September	9.0551	9.2362	4,618	42,653	2,500	23,091	65,744
October 2010	8.1792	8.3428	3,320	27,698	2,500	20,857	48,555
2009/2010 GCR Total			172,026	1,338,631	30,000	243,171	1,581,802

Note:
(1) Monthly Commodity Rate is equal to the System Weighted Average Commodity Cost of Gas (WACCOG) adjusted for losses of 2.0%.

Delmarva Power & Light Company
Calculation of Gas Cost Rate Demand Factors
Applicable To Non-Volumetric DCR Factor Customers
For November 2009 Through October 2010

Description	Amount
Total Gas Demand Expense	28,301,241
Demand Credits:	
Off System Sales & SWAPS Margins	(2,380,000)
Capacity Release Margins	(5,720,000)
FPS Margins	0
Interruptible Gas Transportation Margins	(852,674)
Transition Charges	(11,137)
No Notice Swing Charges	0
Balancing Charges	(464,004)
Unauthorized Overrun	0
Total Demand Revenue Credits	(9,427,815)
Total Firm Gas Supply Demand Expense	18,873,426
Total Demand Expense True-Up	608,230
Adjusted Total Firm Gas Supply Demand Expense	19,481,656

Allocation of Demand Expenses Based on Average Daily and Excess Load Factors:

		System	Volumetric	MVG	LVG
Average Daily Load Allocation @ $ 204.65	204.65	7,342,228	6,996,574	249,264	96,390
Excess Load Allocation (1)		12,139,428	11,575,504	453,422	110,503
Total Demand Costs to be Collected		19,481,656	18,572,078	702,686	206,893
MVG and LVG Allocation		$909,579			
MVG & LVG Forecast MDQ (mcf)		7,966			
Annual Demand Rate (Per MCF of MDQ)		$ 114.18			
Monthly Demand Rate (Per MCF of MDQ)		$ 9.5152			

Note:

(1) Excess load allocation is based on ratio of Excess loads by class to the total for all classes. Design Day, Average Daily, and Excess Loads, in MCF, are as follows:

	Design Day	Average Daily	Excess
MVG	6,265	1,218	5,047
LVG	1,701	471	1,230
Volumetric	163,034	34,188	128,846

Delmarva Power & Light Company
MVG & LVG Demand Factor Revenues
August 2009 Through October 2010
(15 Months Estimated)

2008/2009 GCR Period Monthly Demand Rate, $/Mcf	8.5538
Proposed Monthly Demand Rate, $/Mcf	9.5152

Description	MVG Contract MDQ	MVG Revenue	LVG Contract MDQ	LVG Revenue	Total Revenue
	Mcf	$	Mcf	$	$
August 2009	6,773	57,935	2,551	21,821	79,756
September	6,773	57,935	2,551	21,821	79,756
October 2009	6,773	57,935	2,551	21,821	79,756
November 2009	6,265	59,613	1,701	16,185	75,798
December 2009	6,265	59,613	1,701	16,185	75,798
January 2010	6,265	59,613	1,701	16,185	75,798
February	6,265	59,613	1,701	16,185	75,798
March	6,265	59,613	1,701	16,185	75,798
April	6,265	59,613	1,701	16,185	75,798
May	6,265	59,613	1,701	16,185	75,798
June	6,265	59,613	1,701	16,185	75,798
July	6,265	59,613	1,701	16,185	75,798
August	6,265	59,613	1,701	16,185	75,798
September	6,265	59,613	1,701	16,185	75,798
October 2010	6,265	59,613	1,701	16,185	75,798
2009/2010 GCR Total		715,356		194,220	909,576

Delmarva Power & Light Company
Calculation of Gas Cost Rate Demand Factors
Applicable To Volumetric DCR Customers
For November 2009 Through October 2010

Description	RG, GG, and GL
Total Firm Gas Demand Expense	$ 18,873,426
FPS Margin True-Up	0
Demand Expense True-Up	608,230
Total Recoverable Gas Expenses	$19,481,656
MVG Demand Credit	(715,356)
LVG Demand Credit	(194,220)
Total Demand Credits	$ (909,576)
Demand Revenue collections - RG, GG, GL	$ 18,572,080
Estimated Firm Volumetric Sales (Mcf)	12,478,672
Demand Factor to be Collected in GCR Volumetrically	$1.4883 / Mcf

Delmarva Power & Light Company
Capacity Release & Off System Sales
For July 2008 Through October 2010

Month		Capacity Release Revenue	Off-System Sales Revenue	Off-System Sales Expenses	Off-System Sales Margins	Total Margins	Accumulated Margins	Margins Shared	Percentage of Margins Shared
Jul-08		354,513	18,881,976	18,616,960	265,016	619,529	619,529	619,529	100.00%
Aug-08		364,995	10,974,945	9,245,871	1,729,074	2,094,069	2,713,598	1,891,364	90.32%
Sep-08		353,221	3,061,654	4,128,669	(1,067,015)	(713,794)	1,999,805	(571,035)	80.00%
Oct-08		364,995	3,045,024	2,958,498	86,526	451,521	2,451,325	361,216	80.00%
Nov-08		353,221	2,843,502	2,715,699	127,803	481,024	2,932,349	384,819	80.00%
Dec-08		688,460	965,475	864,703	100,772	789,232	3,721,581	631,385	80.00%
Jan-09		583,728	1,747,939	1,297,324	450,615	1,034,343	4,755,924	827,474	80.00%
Feb-09		588,905	3,647,939	3,212,014	435,925	1,024,830	5,780,754	819,864	80.00%
Mar-09		607,728	4,487,457	4,207,781	279,676	887,404	6,668,158	709,922	80.00%
Apr-09		588,446	3,365,234	3,173,861	191,373	779,819	7,447,977	623,856	80.00%
May-09		603,069	2,797,564	2,682,172	115,392	718,461	8,166,438	574,769	80.00%
Jun-09		587,166	1,816,086	1,758,341	57,745	644,911	8,811,349	515,929	80.00%
Jul-09		603,069	2,376,636	2,326,447	50,189	653,258	653,258	653,257	100.00%
Aug-09	Est.	400,000	186,000	0	186,000	586,000	1,239,258	586,000	100.00%
Sep-09	Est.	400,000	180,000	0	180,000	580,000	1,819,258	580,000	100.00%
Oct-09	Est.	400,000	186,000	0	186,000	586,000	2,405,258	586,000	100.00%
Nov-09	Est.	550,000	300,000	0	300,000	850,000	3,255,258	680,000	80.00%
Dec-09	Est.	550,000	300,000	0	300,000	850,000	4,105,258	680,000	80.00%
Jan-10	Est.	550,000	300,000	0	300,000	850,000	4,955,258	680,000	80.00%
Feb-10	Est.	550,000	300,000	0	300,000	850,000	5,805,258	680,000	80.00%
Mar-10	Est.	550,000	300,000	0	300,000	850,000	6,655,258	680,000	80.00%
Apr-10	Est.	550,000	250,000	0	250,000	800,000	7,455,258	640,000	80.00%
May-10	Est.	550,000	200,000	0	200,000	750,000	8,205,258	600,000	80.00%
Jun-10	Est.	550,000	150,000	0	150,000	700,000	8,905,258	560,000	80.00%
Jul-10	Est.	550,000	150,000	0	150,000	700,000	700,000	700,000	100.00%
Aug-10	Est.	550,000	150,000	0	150,000	700,000	1,400,000	700,000	100.00%
Sep-10	Est.	550,000	150,000	0	150,000	700,000	2,100,000	700,000	100.00%
Oct-10	Est.	550,000	250,000	0	250,000	800,000	2,900,000	800,000	100.00%

Delmarva Power & Light Company
Allocation of Firm Commodity and Demand Expenses
For November 2009 Through October 2010
12 Months Estimated

Description	2009 November	December	2010 January	February	March	April	May	June	July	August	September	October	Total
	$	$	$	$	$	$	$	$	$	$	$	$	$
Allocation of Commodity Expenses:													
LVG Commodity Expenses	52,167	148,506	221,110	251,719	207,068	159,913	108,633	30,515	41,312	47,337	42,653	27,698	1,338,631
Electing MVG Commodity Expenses	17,949	18,528	19,570	19,429	19,549	17,644	19,805	20,519	22,590	23,640	23,091	20,857	243,171
Total Monthly CCR Expenses	70,116	167,034	240,680	271,148	226,617	177,557	128,438	51,034	63,902	70,977	65,744	48,555	1,581,802
Total Annual CCR Expenses	10,111,793	16,781,834	19,333,182	15,994,447	12,649,680	5,799,290	3,654,048	2,766,707	2,777,906	2,856,151	2,850,971	4,462,677	100,038,686
Total Firm Commodity Expenses	10,181,909	16,948,868	19,573,862	16,265,595	12,876,297	5,976,847	3,782,486	2,817,741	2,841,808	2,927,128	2,916,715	4,511,232	101,620,488
Allocation of Demand Expenses:													
MVG Demand Expenses	59,613	59,613	59,613	59,613	59,613	59,613	59,613	59,613	59,613	59,613	59,613	59,613	715,356
LVG Demand Expenses	16,185	16,185	16,185	16,185	16,185	16,185	16,185	16,185	16,185	16,185	16,185	16,185	194,220
Total Non-Volumetric DCR Expenses	75,798	75,798	75,798	75,798	75,798	75,798	75,798	75,798	75,798	75,798	75,798	75,798	909,576
Total Volumetric DCR Expenses	1,500,999	1,496,671	1,511,885	1,505,039	1,518,479	1,553,308	1,564,923	1,610,559	1,448,360	1,467,559	1,445,488	1,340,579	17,963,847
Total Firm Demand Expenses	1,576,797	1,572,469	1,587,683	1,580,837	1,594,277	1,629,106	1,640,721	1,686,357	1,524,158	1,543,357	1,521,286	1,416,377	18,873,426

Delmarva Power and Light Company
Comparison of Actual Gas Demand Costs to
Estimated Gas Demand Costs
For Delmarva Firm Gas Operations For the Period
For November 2009 Through October 2010

Description	Demand Expense Actual (1)	Demand Expense Estimated (2)	Monthly Variance	Cumulative Variance	Interest Expense (3)	Demand Costs True - Up
	$	$	$	$	$	$
August 2008	581,113	562,605	18,508	18,508	82	18,590
September	1,828,441	1,825,709	2,732	21,240	94	2,826
October	1,870,288	1,825,709	44579	65,819	274	44,853
November	1,936,945	2,160,827	(223,882)	(158,063)	(659)	(224,541)
December 2008	1,983,051	2,160,827	(177,776)	(335,839)	(1,399)	(179,175)
January 2009	2,380,064	2,160,827	219,237	(116,602)	(439)	218,798
February	2,467,479	2,160,827	306,652	190,050	716	307,368
March	2,345,373	2,160,827	184,546	374,596	1,411	185,957
April	2,338,039	2,160,827	177,212	551,808	1,550	178,762
May	2,371,162	2,114,662	256,500	808,308	2,270	258,770
June	2,266,079	2,114,662	151,417	959,725	2,695	154,112
July	2,346,420	2,114,662	231,758	1,191,483	3,227	234,985
August	1,914,826	2,114,662	(199,836)	991,647	2,686	(197,150)
September	1,914,826	2,114,662	(199,836)	791,811	2,145	(197,692)
October 2009	1,914,826	2,114,662	(199,836)	591,975	1,603	(198,233)
Total	30,458,932	29,866,957	591,975		16,255	608,230

Notes:

(1) The Months August 2009 through October 2009 in the column titled "Actuals" are based on the Company's estimates from the August 2009 GCR filing.

(2) Estimated Demand Expenses for the period August 2009 through October 2009 are based on projections from the August 2008 GCR filing.

(3) Interest expense for August 2008 and September 2008 is based on the FERC Refund Interest Rate of 5.30% applied to the cumulative monthly variance.
Interest expense for October 2008 through December 2008 is based on the FERC Refund Interest Rate of 5.00% applied to the cumulative monthly variance
Interest expense for January 2009 through March 2009 is based on the FERC Refund Interest Rate of 4.52% applied to the cumulative monthly variance.
Interest expense for April 2009 through June 2009 is based on the FERC Refund Interest Rate of 3.37% applied to the cumulative monthly variance.
Interest expense for July 2009 through October 2009 is based on the FERC Refund Interest Rate of 3.25% applied to the cumulative monthly variance.

Delmarva Power & Light Company
Comparison of Gas Expense and Recovery
For Delaware Firm Gas Operations
For November 2009 Through October 2010
12 Months Estimated

Billing Month	Firm Sales (Mcf)	Total GCR Revenue ($)	Total Gas Cost ($)	(Over) or Under Recovery Monthly ($)	Deferred Fuel Balance YTD ($)	% (Over) or Under Recovery (%)
Estimated Deferred Fuel Balance @ October 31, 2009					3,256,259	
FPS WACCOG True-Ups					0	
Estimated Interest Expense					15,815	
Estimated Deferred Fuel Balance @ November 1, 2009					3,272,074	
November 2009	946,699	9,649,708	11,758,706	2,108,998	5,381,072	
December 2009	1,732,815	16,230,498	18,521,337	2,290,839	7,671,911	
January 2010	2,191,325	20,515,313	21,161,545	646,232	8,318,142	
February	2,435,379	22,795,377	17,846,432	(4,948,945)	3,369,197	
March	2,129,614	19,944,173	14,470,574	(5,473,599)	(2,104,403)	
April	1,313,454	12,297,737	7,605,953	(4,691,784)	(6,796,187)	
May	657,217	6,193,310	5,423,207	(770,103)	(7,566,290)	
June	390,345	3,716,291	4,504,098	787,807	(6,778,483)	
July	311,946	2,986,893	4,365,966	1,379,073	(5,399,410)	
August	280,846	2,698,506	4,470,485	1,771,979	(3,627,431)	
September	302,229	2,900,380	4,438,001	1,537,621	(2,089,810)	
October 2010	403,473	3,837,191	5,927,609	2,090,418	608	0.0%
Total	13,095,343	123,765,377	120,493,911	(3,271,466)		

Notes:

(1) November 2009 through October 2010 Fuel Revenue is based on GCR of $9.3959 / Mcf .

(2) Estimated Gas Cost Expenses and WACCOGs are based on the July 31, 2009 NYMEX closing prices.

Delmarva Power & Light Company
Development of Annual Commodity and Demand Expenses
For November 2009 Through October 2010
12 Months Estimated

Description	2009		2010										Total
	November	December	January	February	March	April	May	June	July	August	September	October	$
Total Gas Supply Expense	12,568,813	19,337,798	21,971,037	18,662,657	15,269,545	8,368,953	6,123,781	5,157,199	5,181,680	5,267,210	5,256,687	6,850,757	130,016,120
Total Gas Commodity Expense	10,187,294	16,956,279	19,589,518	16,281,138	12,888,026	5,987,434	3,788,427	2,821,845	2,846,326	2,931,856	2,921,333	4,515,403	101,714,879
Commodity Credits:													
Off System Sales - Fuel Cost (1)	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash Outs	0	0	0	0	0	0	0	0	0	0	0	0	0
Company Use Gas	(5,385)	(7,411)	(15,656)	(15,543)	(11,729)	(10,587)	(5,941)	(4,104)	(4,518)	(4,728)	(4,618)	(4,171)	(94,391)
Total Commodity Fuel Credits	(5,385)	(7,411)	(15,656)	(15,543)	(11,729)	(10,587)	(5,941)	(4,104)	(4,518)	(4,728)	(4,618)	(4,171)	(94,391)
Total Firm Commodity Cost of Gas	10,181,909	16,948,868	19,573,862	16,265,595	12,876,297	5,976,847	3,782,486	2,817,741	2,841,808	2,927,128	2,916,715	4,511,232	101,620,488
Total Gas Demand Expense	2,381,519	2,381,519	2,381,519	2,381,519	2,381,519	2,381,519	2,335,354	2,335,354	2,335,354	2,335,354	2,335,354	2,335,354	28,301,241
Demand Credits (% varies)													
Off-System Sales & Swaps	(240,000)	(240,000)	(240,000)	(240,000)	(240,000)	(200,000)	(160,000)	(120,000)	(150,000)	(150,000)	(150,000)	(250,000)	(2,380,000)
Capacity Release	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(440,000)	(550,000)	(550,000)	(550,000)	(550,000)	(5,720,000)
Interruptible Gas Transportation	(81,884)	(88,642)	(73,428)	(80,274)	(66,834)	(73,746)	(55,966)	(50,330)	(72,529)	(53,330)	(75,401)	(80,310)	(852,674)
Subtotal	(761,884)	(768,642)	(753,428)	(760,274)	(746,834)	(713,746)	(655,966)	(610,330)	(772,529)	(753,330)	(775,401)	(880,310)	(8,952,674)
Demand Credits @ 100%													
Transition Charges	(4,171)	(1,741)	(1,741)	(1,741)	(1,741)	0	0	0	0	0	0	0	(11,137)
No-Notice Swing Charges	0	0	0	0	0	0	0	0	0	0	0	0	0
Balancing Charges	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(464,004)
Unauthorized Overrun	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	(42,838)	(40,408)	(40,408)	(40,408)	(40,408)	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(38,667)	(475,141)
Total Demand Credits	(804,722)	(809,050)	(793,836)	(800,682)	(787,242)	(752,413)	(694,633)	(648,997)	(811,196)	(791,997)	(814,068)	(918,977)	(9,427,815)
Total Firm Demand Expenses	1,576,797	1,572,469	1,587,683	1,580,837	1,594,277	1,629,106	1,640,721	1,686,357	1,524,158	1,543,357	1,521,286	1,416,377	18,873,426
Total Firm Gas Expenses	11,758,706	18,521,337	21,161,545	17,846,432	14,470,574	7,605,953	5,423,207	4,504,098	4,365,966	4,470,485	4,438,001	5,927,609	120,493,914

Note: (1) The Cost of Fuel for Off-System Sales and Cash-Outs have not been included in the estimated Commodity Expenses shown on this Schedule and therefore does not require removal.

Delmarva Power & Light Company
Comparison of Gas Expense and Recovery
For Delaware Firm Gas Operations
For November 2008 Through October 2009
9 Months Actual, 3 Months Updated Estimates

Billing Month	Firm Sales Mcf	Total Gas Cost Recovery ($)	Total Gas Cost ($)	(Over) or Under Recovery Monthly ($)	Deferred Fuel Balance YTD ($)	% (Over) or Under Recovery (%)
Deferred Fuel Balance @ October 31, 2008					499,807	
FPS True-Up					3,787	
Interest Expense					(267,414)	
Adjusted Deferred Fuel Balance @ November 1, 2008					236,180	
November 2008	922,942	9,944,216	17,417,654	7,473,438	7,709,618	
December 2008	1,930,499	22,660,816	21,615,966	(1,044,850)	6,664,768	
January 2009	2,466,153	28,918,262	27,832,614	(1,085,648)	5,579,120	
February	2,556,822	29,969,357	22,635,482	(7,333,875)	(1,754,755)	
March	2,022,344	22,941,394	20,173,393	(2,768,001)	(4,522,756)	
April	1,239,378	13,597,458	11,248,919	(2,348,539)	(6,871,295)	
May	585,420	6,428,772	6,738,320	309,548	(6,561,747)	
June	364,771	4,154,988	5,984,072	1,829,084	(4,732,663)	
July	286,643	3,183,024	7,304,132	4,121,108	(611,555)	
August	277,251	3,100,478	4,211,763	1,111,285	499,730	
September	301,537	3,371,036	4,310,222	939,186	1,438,916	
October 2009	412,305	4,579,986	6,397,329	1,817,343	3,256,259	2.1%
Total	13,366,065	152,849,787	155,869,865	3,020,079		

Notes:

(1) November 1, 2008 through February 28, 2009 Fuel Revenue is based on GCR of $11.7560/Mcf as approved by Order No. 7444 in Docket No. 08-266F dated September 16, 2008.

(2) March 1, 2009 through October 31, 2009 Fuel Revenue is based on GCR of $10.9812/Mcf as approved by Order No. 7532 in Docket No. 08-266F dated February 5, 2009.

(3) Estimated Gas Cost Expenses and WACCOGs are based on the July 31, 2009 NYMEX closing prices.

Delmarva Power & Light Company
Development of Annual Commodity and Demand Expenses
For November 2008 Through October 2009
9 Months Actual, 3 Months Updated Estimates

Description	2008 November	2008 December	2009 January	2009 February	2009 March	2009 April	2009 May	2009 June	2009 July	2009 August	2009 September	2009 October	Total
	$	$	$	$	$	$	$	$	$	$	$	$	$
Total Gas Supply Expense	20,696,492	23,221,868	30,065,691	26,768,451	25,216,797	15,180,386	10,096,645	8,350,579	10,371,465	4,898,193	5,013,578	7,110,410	186,990,555
Total Gas Commodity Expense	18,759,547	21,238,817	27,685,627	24,300,972	22,871,424	12,842,347	7,725,483	6,084,500	8,025,045	2,983,367	3,098,752	5,195,584	160,811,465
Fuel Credits:													
FPS Gas - Fuel Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
Off System Sales - Fuel Cost (1)	(2,715,699)	(864,703)	(1,297,324)	(3,212,014)	(4,207,781)	(3,173,861)	(2,682,172)	(1,758,341)	(2,326,447)	0	0	0	(22,238,342)
Cash Outs	(67,931)	13,184	0	(6)	(9,576)	(2,953)	(3,924)	(1,186)	0	0	0	0	(72,392)
Company Use Gas	(6,758)	(9,255)	(13,547)	(15,524)	(16,039)	(17,345)	(5,175)	(2,754)	(3,008)	(4,811)	(4,899)	(4,800)	(103,915)
Total Fuel Credits	(2,790,388)	(860,774)	(1,310,871)	(3,227,544)	(4,233,396)	(3,194,159)	(2,691,271)	(1,762,281)	(2,329,455)	(4,811)	(4,899)	(4,800)	(22,414,649)
Total Gas Commodity Expense	15,969,159	20,378,043	26,374,756	21,073,428	18,638,028	9,648,188	5,034,212	4,322,219	5,695,590	2,978,556	3,093,853	5,190,784	138,396,816
Total Gas Demand Expense	1,936,945	1,983,051	2,380,064	2,467,479	2,345,373	2,338,039	2,371,162	2,266,079	2,346,420	1,914,826	1,914,826	1,914,826	26,179,090
Demand Credits (% varies)													
Off-System Sales & Swaps	(102,243)	(80,617)	(360,492)	(348,740)	(223,740)	(153,099)	(92,313)	(46,196)	(50,188)	(186,000)	(180,000)	(186,000)	(2,009,628)
Capacity Release	(282,576)	(550,768)	(466,982)	(471,124)	(486,182)	(470,757)	(482,456)	(469,733)	(603,069)	(400,000)	(400,000)	(400,000)	(5,483,647)
FPS Margins	0	0	0	0	0	0	0	0	0	0	0	0	0
Interruptible Gas Transportation	(71,764)	(67,022)	(37,309)	(44,547)	(53,083)	(80,904)	(63,401)	(58,561)	(61,563)	(55,185)	(78,023)	(83,104)	(754,466)
Subtotal	(456,583)	(698,407)	(864,783)	(864,411)	(763,005)	(704,760)	(638,170)	(574,490)	(714,820)	(641,185)	(658,023)	(669,104)	(8,247,741)
Demand Credits @ 100 %													
Transition Charges	(1,277)	(5,563)	(7,993)	(7,993)	(7,635)	(6,361)	(154)	(9,734)	5,395	(9,734)	(9,734)	(8,477)	(69,261)
Balancing Charges	(30,590)	(41,158)	(31,170)	(33,021)	(37,278)	(26,187)	(28,730)	(20,002)	(28,453)	(30,700)	(30,700)	(30,700)	(368,689)
No Notice Swing Charges	0	0	0	0	0	0	0	0	0	0	0	0	0
Unauthorized Overrun	0	0	(18,260)	0	(2,090)	0	0	0	0	0	0	0	(20,350)
Total Demand Credits	(488,450)	(745,128)	(922,206)	(905,425)	(810,008)	(737,308)	(667,054)	(604,226)	(737,878)	(681,619)	(698,457)	(708,281)	(8,706,041)
Total Firm Demand Expenses	1,448,495	1,237,923	1,457,858	1,562,054	1,535,365	1,600,731	1,704,108	1,661,853	1,608,542	1,233,207	1,216,369	1,206,545	17,473,049
Total Firm Gas Expenses	17,417,654	21,615,966	27,832,614	22,635,482	20,173,393	11,248,919	6,738,320	5,984,072	7,304,132	4,211,763	4,310,222	6,397,329	155,869,865

Note: (1) The Cost of Fuel for Off-System Sales and Cash-Outs have not been included in the estimated Commodity Expenses shown on this Schedule and therefore does not require removal.

Delmarva Power & Light Company
Comparison of Gas Expense and Recovery
For Delaware Firm Gas Operations
For November 2007 Through October 2008
12 Months Actual

Billing Month	Firm Sales	Total GCR Revenue	Total Gas Cost	(Over) or Under Recovery Monthly	Deferred Fuel Balance YTD	% (Over) or Under Recovery
	(Mcf)	($)	($)	($)	($)	(%)
Deferred Fuel Balance Including FPS WACCOG True-Up @ October 31, 2007					(5,730,652)	
Interest Expense					(205,459)	
Deferred Fuel Balance @ November 1, 2007					(5,936,111)	
November 2007	843,788	8,335,467	13,402,971	5,067,504	(868,607)	
December 2007	1,807,974	17,407,403	19,969,704	2,562,301	1,693,693	
January 2008	2,282,765	21,980,538	21,103,681	(876,857)	816,836	
February 2008	2,377,869	22,889,167	19,875,983	(3,013,184)	(2,196,348)	
March 2008	2,051,257	19,764,898	16,046,394	(3,718,504)	(5,914,852)	
April 2008	1,256,723	12,147,147	8,550,667	(3,596,480)	(9,511,332)	
May 2008	615,517	6,066,179	7,283,561	1,217,382	(8,293,950)	
June 2008	418,096	4,193,835	5,674,421	1,480,586	(6,813,364)	
July 2008	304,074	3,269,402	4,972,033	1,702,632	(5,110,733)	
August 2008	290,851	2,981,430	2,844,484	(136,946)	(5,247,679)	
September 2008	293,515	2,930,048	4,060,788	1,130,740	(4,116,939)	
October 2008	404,360	3,972,191	8,588,938	4,616,747	499,807	0.4%
Total	12,946,789	125,937,705	132,373,624	6,435,919		

Notes:

(1) November 1, 2007 through October 31, 2008 Fuel Revenue is based on GCR of $9.6517/Mcf as approved by Order No. 7439 in Docket No. 07-239F dated September 16, 2008.

Delmarva Power & Light Company
Development of Annual Commodity and Demand Expenses
For November 2007 Through October 2008
12 Months Actual

Description	2007 November	2007 December	2008 January	2008 February	2008 March	2008 April	2008 May	2008 June	2008 July	2008 August	2008 September	2008 October	Total $
Total Gas Supply Expense	20,569,685	23,126,142	26,260,408	27,456,013	26,362,433	23,326,280	19,221,201	25,330,925	24,332,242	14,082,603	7,707,004	12,010,356	249,785,292
Total Gas Commodity Expense	18,985,323	21,058,682	24,155,165	25,549,615	24,594,755	21,310,197	17,155,098	23,505,451	22,510,900	13,501,490	5,878,564	10,140,068	228,345,308
Commodity Credits:													
Flexibly Priced Sales - Fuel Cost	(15,378)	(13,041)	0	0	0	0	0	0	0	0	0	0	(28,419)
Off System Sales - Fuel Cost (1)	(6,406,341)	(2,367,343)	(3,758,381)	(6,295,754)	(9,442,825)	(13,729,714)	(10,938,683)	(18,894,333)	(18,616,960)	(9,245,871)	(4,128,669)	(2,958,498)	(106,783,372)
Cash Out Sales	(38,124)	(39,849)	(6,765)	0	0	(239,782)	(5,808)	(19,295)	(27,346)	(17,209)	0	(1,616)	(395,595)
Company Use Gas	(4,810)	(8,519)	(18,986)	(12,946)	(11,274)	(13,738)	(8,619)	(8,314)	(4,678)	(4,173)	(3,732)	(5,031)	(104,818)
Total Commodity Fuel Credits	(6,464,653)	(2,428,552)	(3,784,131)	(6,308,700)	(9,454,099)	(13,983,234)	(10,953,110)	(18,921,942)	(18,648,984)	(9,267,252)	(4,132,401)	(2,965,146)	(107,312,203)
Total Firm Commodity Cost of Gas	12,520,670	18,630,130	20,371,034	19,240,915	15,140,656	7,326,963	6,201,988	4,583,509	3,861,916	4,234,238	1,746,163	7,174,922	121,033,105
Total Gas Demand Expense	1,584,362	2,067,460	2,105,243	1,906,398	1,767,678	2,016,083	2,066,103	1,825,474	1,821,342	581,113	1,828,441	1,870,288	21,439,984
Demand Credits (% varies)													
Off-System Sales & Swaps	(136,754)	(146,239)	(796,793)	(748,146)	(288,265)	(353,123)	(591,333)	(369,084)	(265,016)	(1,561,700)	853,612	(69,221)	(4,472,062)
Capacity Release	(442,056)	(456,792)	(456,791)	(427,322)	(456,791)	(322,430)	(333,179)	(280,540)	(354,513)	(329,663)	(282,576)	(291,996)	(4,434,650)
FPS Margins	(883)	(1,441)	0	0	0	0	0	0	0	0	0	0	(2,324)
Interruptible Gas Transportation	(92,415)	(91,466)	(76,130)	(60,162)	(88,682)	(81,614)	(60,398)	(65,185)	(75,238)	(69,818)	(75,469)	(80,090)	(916,667)
Subtotal	(672,108)	(695,938)	(1,329,714)	(1,235,629)	(833,738)	(757,168)	(984,910)	(714,809)	(694,767)	(1,961,182)	495,566	(441,306)	(9,825,702)
Demand Credits @ 100%													
Transition Charges	(5,359)	(6,459)	(5,511)	(4,430)	(2,854)	(2,854)	19,688	(2,854)	(2,854)	3,267	5,994	(1,100)	(5,326)
No-Notice Swing Charges	(272)	(220)	0	0	0	0	0	0	0	0	0	0	(492)
Balancing Charges	(24,321)	(25,266)	(37,371)	(29,246)	(25,348)	(30,938)	(19,308)	(16,518)	(13,984)	(12,953)	(15,375)	(13,866)	(264,494)
Unauthorized Overrun	0	0	0	(2,025)	0	(1,420)	0	(380)	380	0	0	0	(3,445)
Subtotal	(29,952)	(31,945)	(42,882)	(35,701)	(28,202)	(35,212)	380	(19,752)	(16,458)	(9,685)	(9,382)	(14,966)	(273,757)
Total Demand Credits	(702,060)	(727,883)	(1,372,596)	(1,271,330)	(861,940)	(792,380)	(984,530)	(734,561)	(711,225)	(1,970,867)	486,185	(456,272)	(10,099,459)
Total Firm Demand Expenses	882,302	1,339,577	732,647	635,068	905,738	1,223,703	1,081,573	1,090,913	1,110,117	(1,389,754)	2,314,625	1,414,015	11,340,525
	13,402,973	19,969,707	21,103,681	19,875,983	16,046,394	8,550,667	7,283,561	5,674,422	4,972,033	2,844,484	4,060,788	8,588,938	132,373,630

Delmarva Power & Light Company
Interest Calculation
For November 2008 Through October 2009
9 Months Actual, 3 Months Updated Estimates

						Interest (1) (2)		
Month	Beginning Balance ($)	Ending Balance ($)	Average Balance ($)	Average Balance Within Band ($)	Interest (1) (2) ($)	Excess Excess Balance ($)	Interest ($)	Total Interest ($)
November 2008	236,180	7,709,618	3,972,899	3,972,899	16,554	0	0	16,554
December 2008	7,709,618	6,664,768	7,187,193	7,187,193	29,947	0	0	29,947
January 2009	6,664,768	5,579,120	6,121,944	6,121,944	23,059	0	0	23,059
February	5,579,120	(1,754,755)	1,912,183	1,912,183	7,203	0	0	7,203
March	(1,754,755)	(4,522,756)	(3,138,756)	(3,138,756)	(11,823)	0	0	(11,823)
April	(4,522,756)	(6,871,295)	(5,697,026)	(5,697,026)	(15,999)	0	0	(15,999)
May	(6,871,295)	(6,561,747)	(6,716,521)	(6,716,521)	(18,862)	0	0	(18,862)
June	(6,561,747)	(4,732,663)	(5,647,205)	(5,647,205)	(15,859)	0	0	(15,859)
July	(4,732,663)	(611,555)	(2,672,109)	(2,672,109)	(7,237)	0	0	(7,237)
August	(611,555)	499,730	(55,913)	(55,913)	(151)	0	0	(151)
September	499,730	1,438,916	969,323	969,323	2,625	0	0	2,625
October 2009	1,438,916	3,256,259	2,347,588	2,347,588	6,358	0	0	6,358
Total Interest Expense From 11/1/07 to 10/31/08								15,815

Notes:
(1) Average deferred fuel balance interest band is 4 - 1/2% of $155,869,865 or $7,014,144 .
(2) Effective March 1, 1999, the interest rate on both over- and under-recoveries is the FERC Natural Gas Interest Factor, which is as follows:

Nov & Dec, 2007	5.00%	Jan - Mar, 2008	4.52%
Apr - Jun, 2008	3.37%	Jul - Oct, 2008	3.25%

Delmarva Power & Light Company
Summary of Large Volume Gas Customers and Electing MVG Gas Customers WACCOG True-up
For the Months July 2008 through June 2009

Actual Month	Billing Month	Estimated Commodity Cost Rate (1)	Actual Commodity Cost Rate	Over (Under)	Firm Sales	Monthly Commodity Revenue	Over (Under)
Jun-08	Jul-08	11.7897	11.6595	0.1302	24,685	$291,029	$3,214
Jul-08	Aug-08	12.6470	11.5141	1.1329	26,639	$336,903	$30,179
Aug-08	Sep-08	9.8944	8.2439	1.6505	23,039	$227,957	$38,026
Sep-08	Oct-08	9.2858	4.9333	4.3525	22,436	$208,336	$97,653
Oct-08	Nov-08	10.1999	9.0103	1.1896	29,888	$304,855	$35,555
Nov-08	Dec-08	9.8778	10.1500	(0.2722)	38,970	$384,938	($10,608)
Dec-08	Jan-09	9.6548	8.8976	0.7572	46,912	$452,926	$35,522
Jan-09	Feb-09	9.9392	8.5760	1.3632	57,760	$574,088	$78,738
Feb-09	Mar-09	9.2870	10.0222	(0.7352)	47,936	$445,182	($35,243)
Mar-09	Apr-09	9.3127	10.3565	(1.0438)	40,810	$380,051	($42,597)
Apr-09	May-09	8.1746	9.9666	(1.7920)	25,735	$210,373	($46,117)
May-09	Jun-09	8.0356	10.2595	(2.2239)	6,086	$48,905	($13,535)
Adjustment for Prior Period							($132,053)
Total					390,896	$3,865,543	$38,734
Variance							1.00%

Note (1) The Estimated Commodity Cost Rate excludes the $0.3494 charge associated with the 2006/2007 WACCOG True-Up, was in effect on June 1, 2008.
The Estimated Commodity Cost Rate excludes the $1.1179associated with the 2007/2008 WACCOG True-Up, was in effect on June 1, 2008.

Billing Month	LVG Sales	Refund Credit Rate	Refund Amount
June 2007 through July 2008 Balance			($460,825)
Jul-08	24,685	$0.34740	$8,576
Aug-08	26,639	$0.34740	$9,254
Sep-08	23,039	$0.34740	$8,004
Oct-08	22,436	$0.34740	$7,794
Nov-08	29,888	$1.11790	$33,412
Dec-08	38,970	$1.11790	$43,565
Jan-09	46,912	$1.11790	$52,443
Feb-09	57,760	$1.11790	$64,570
Mar-09	47,936	$1.11790	$53,588
Apr-09	40,810	$1.11790	$45,621
May-09	25,735	$1.11790	$28,769
Jun-09	6,086	$1.11790	$6,804
Total	390,896		$328,772
Amount of Prior Period Credit Remaining			($132,053)

Delmarva Power & Light Company
Firm Sales

Description	Twelve Months Estimated November 2009 Through October 2010 (Mcf)	9 Months Actual 3 Months Estimated November 2008 Through October 2009 (Mcf)	Twelve Months Actual November 2007 Through October 2008 (Mcf)
November	946,699	922,942	843,788
December	1,732,815	1,930,499	1,807,974
January	2,191,325	2,466,153	2,282,765
February	2,435,379	2,556,822	2,377,869
March	2,129,614	2,022,344	2,051,257
April	1,313,454	1,239,378	1,256,723
May	657,217	585,420	615,517
June	390,345	364,771	418,096
July	311,946	286,643	304,074
August	280,846	277,251	290,851
September	302,229	301,537	293,515
October	403,473	412,305	404,360
Total	13,095,343	13,366,065	12,946,789

Delmarva Power & Light Company
Gas Costs

Description	Twelve Months Estimated November 2009 Through October 2010 $	9 Months Actual 3 Months Estimated November 2008 Through October 2009 $	Twelve Months Actual November 2007 Through October 2008 $
Total Gas Supply Expenses	130,016,120	186,990,555	249,785,292
Expense Credits			
FPS Gas - Fuel Costs	0	0	(28,419)
Off System Sales - Fuel Cost (1)	0	(22,238,342)	(106,783,372)
Cash Outs	0	(72,392)	(395,595)
Company Use Gas	(94,391)	(103,915)	(104,818)
Off System Sales / Swaps	(2,380,000)	(2,009,628)	(4,472,062)
Capacity Release	(5,720,000)	(5,483,647)	(4,434,650)
FPS Margins	0	0	(2,324)
Interruptible Gas Transportation	(852,674)	(754,466)	(916,667)
Transition Charges	(11,137)	(69,261)	(5,326)
Balancing Charges	(464,004)	(368,689)	(264,494)
No Notice Swing Charges	0	0	(492)
Unauthorized Overrun	0	(20,350)	(3,445)
Total	120,493,914	155,869,865	132,373,630

Notes:
(1) The fuel costs associated with Off-System sales are not included in Estimated Total Gas Supply Expenses, and do not require removal.

Delmarva Power & Light Company
Comparison of Gas Expense and Recovery
For Delaware Firm Gas Operations
August 2008 Through July 2009
12 Months Actual

Billng Month	Firm Sales Mcf	Total Gas Cost Recovery ($)	Total Gas Cost ($)	(Over) or Under Recovery Monthly ($)	Deferred Fuel Balance YTD ($)
Deferred Fuel Balance @ July 31, 2008					(5,110,736)
August 2008	290,851	2,981,430	2,844,483	(136,947)	(5,247,683)
September	293,515	2,930,048	4,060,791	1,130,743	(4,116,940)
October 2008	414,900	3,972,191	8,588,938	4,616,747	499,807
FPS True-Up (July 2006 - June 2008)					3,787
Interest Expense (November 2006 - October 2008)					(267,414)
Adjusted Balance					236,180
November 2008	922,942	9,944,216	17,417,654	7,473,438	7,709,618
December 2008	1,930,499	22,660,816	21,615,966	(1,044,850)	6,664,768
January 2009	2,466,153	28,918,262	27,832,614	(1,085,648)	5,579,120
February	2,556,822	29,969,357	22,635,482	(7,333,875)	(1,754,755)
March	2,022,344	22,941,394	20,173,393	(2,768,002)	(4,522,758)
April	1,239,378	13,597,458	11,248,919	(2,348,539)	(6,871,296)
May	585,420	6,428,772	6,738,321	309,548	(6,561,747)
June	364,771	4,154,988	5,984,073	1,829,084	(4,732,663)
July 2009	286,643	3,183,024	7,304,132	4,121,108	(611,553)
Total	13,374,238	151,681,956	156,444,766	4,762,807	

Notes:
1) Gas Cost Recovery Revenue for August 2007 through October 2007 is based on the GCR of $10.2357 as approved by Order No. 7219 in Docket No. 06-285F dated July 03, 2007.
2) Gas Cost Recovery Revenue for November 2007 through July 2008 is based on the GCR of $9.6517 as approved by Order No. 7285 in Docket No. 07-239F dated September 18, 2007.

Delmarva Power & Light Company
Development of Annual Commodity and Demand Expenses
August 2008 Through July 2009
12 Months Actual

Description	2008 August	2008 September	2008 October	2008 November	2008 December	2009 January	2009 February	2009 March	2009 April	2009 May	2009 June	2009 July	Total
	$	$	$	$	$	$	$	$	$	$	$	$	$
Total Gas Supply Expense	14,082,603	7,707,005	12,010,356	20,696,492	23,221,868	30,065,691	26,768,451	25,216,797	15,180,386	10,096,645	8,350,579	10,371,465	203,768,338
Total Gas Commodity Expense	13,501,490	5,878,564	10,140,068	18,759,547	21,238,817	27,685,627	24,300,972	22,871,424	12,842,347	7,725,483	6,084,500	8,025,045	179,053,884
Fuel Credits:													
FPS Gas - Fuel Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
Off System Sales - Fuel Cost	(9,245,871)	(4,128,669)	(2,958,498)	(2,715,699)	(864,703)	(1,297,324)	(3,212,014)	(4,207,781)	(3,173,861)	(2,682,172)	(1,758,341)	(2,326,447)	(38,571,380)
Cash Outs	(17,209)	1	(1,616)	(67,931)	13,184	0	(6)	(9,576)	(2,953)	(3,924)	(1,186)	0	(91,216)
Company Use Gas	(4,173)	(3,732)	(5,031)	(6,758)	(9,255)	(13,547)	(15,524)	(16,039)	(17,345)	(5,175)	(2,754)	(3,008)	(102,341)
Total Fuel Credits	(9,267,253)	(4,132,400)	(2,965,145)	(2,790,388)	(860,774)	(1,310,871)	(3,227,544)	(4,233,396)	(3,194,159)	(2,691,271)	(1,762,281)	(2,329,455)	(38,764,937)
Total Gas Commodity Expense	4,234,237	1,746,164	7,174,923	15,969,159	20,378,043	26,374,756	21,073,428	18,638,028	9,648,188	5,034,212	4,322,219	5,695,590	140,288,947
Total Gas Demand Expense	581,113	1,828,441	1,870,288	1,936,945	1,983,051	2,380,064	2,467,479	2,345,373	2,338,039	2,371,162	2,266,079	2,346,420	24,714,454
Demand Credits @ 80%													
Off-System Sales & Swaps	(1,561,700)	853,612	(69,221)	(102,243)	(80,617)	(360,492)	(348,740)	(223,740)	(153,099)	(92,313)	(46,196)	(50,188)	(2,234,937)
Capacity Release	(329,663)	(282,576)	(291,996)	(282,576)	(550,768)	(466,982)	(471,124)	(486,182)	(470,757)	(482,456)	(469,733)	(603,069)	(5,187,882)
FPS Margins	0	0	0	0	0	0	0	0	0	0	0	0	0
Interruptible Gas Transportation	(69,818)	(75,469)	(80,090)	(71,764)	(67,022)	(37,309)	(44,547)	(53,083)	(80,904)	(63,401)	(58,561)	(61,563)	(763,531)
Subtotal	(1,961,181)	495,567	(441,307)	(456,583)	(698,407)	(864,783)	(864,411)	(763,005)	(704,760)	(638,170)	(574,490)	(714,820)	(8,186,350)
Demand Credits @ 100 %													
I T Surcharges	0	0	0	0	0	0	0	0	0	0	0	0	0
Transition Charges	3,267	5,994	(1,100)	(1,277)	(5,563)	(7,993)	(7,993)	(7,635)	(6,361)	(154)	(9,734)	5,395	(33,154)
No Notice Swing Charges	0	0	0	0	0	0	0	0	0	0	0	0	0
Balancing Charges	(12,953)	(15,375)	(13,866)	(30,590)	(41,158)	(31,170)	(33,021)	(37,278)	(26,187)	(28,730)	(20,002)	(28,453)	(318,783)
Unauthorized Overrun	0	0	0	0	0	(18,260)	0	(2,090)	0	0	0	0	(20,350)
Total Demand Credits	(1,970,867)	486,186	(456,273)	(488,450)	(745,128)	(922,206)	(905,425)	(810,008)	(737,308)	(667,054)	(604,226)	(737,878)	(8,558,637)
Total Firm Demand Expenses	(1,389,754)	2,314,627	1,414,015	1,448,495	1,237,923	1,457,858	1,562,053	1,535,365	1,600,731	1,704,108	1,661,853	1,608,542	16,155,817
Total Firm Gas Expenses	2,844,483	4,060,791	8,588,938	17,417,654	21,615,966	27,832,614	22,635,481	20,173,394	11,248,919	6,738,321	5,984,073	7,304,132	156,444,767

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RATES AND CHARGES
CORE SALES RATE LEAF

SERVICE CLASSIFICATION	BASE RATE	GAS COST RATE	TOTAL	BASIS	
Residential Gas Sales Service ("RG")					
Customer Charge	$9.56	--	$9.56	per month	
Commodity Charge	$0.421010	$0.93959	$1.360600	per CCF	Deleted: 09812 . $1.519130
Space Heating Commodity Charge 1/					
Over 50 CCF	$0.337840	$0.93959	$1.277430	per CCF	Deleted: 09812 . $1.435960
Environmental Surcharge Rider	$0.00175		$0.00175	per CCF	
General Gas Sales Service ("GG")					
Customer Charge	$27.31	--	$27.31	per month	
Commodity Charge					
First 750 CCF	$ 0.34975	$0.93959	$1.28934	per CCF	Deleted: 09812 . $1.44787
Over 750 CCF	$ 0.26125	$0.93959	$1.20084	per CCF	Deleted: 1.09812 . $1.35937
Environmental Surcharge Rider	$0.00175	--	$0.00175	per CCF	
Gas Lighting Sales Service ("GL")					
(Estimated Usage - 15 CCF per month)					
Monthly Charge	$ 5.92	$14.09	$20.01	per gas light	Deleted: 16.47 . $22.39
Medium Volume Gas Sales Service ("MVG")					
Customer Charge	$419.27	--	$419.27	per month	
Demand Charge	$ 13.39	$9.5152	$ 22.9052	per MCF of Billing MDQ	Deleted: 8.5538 . $ 21.9438
Commodity Charge 2/	$ 0.429790	$7.9076	$ 8.337390	per MCF	Deleted: 9.7555 . $ 10.185290
Environmental Surcharge Rider	$0.01748		$0.01748	per MCF	
Large Volume Gas Sales Service ("LVG")					
Customer Charge	$634.58	--	$634.58	per month	
Demand Charge	$ 8.247210	$9.5152	$ 17.762410	per MCF of Billing MDQ	Deleted: 8.5538 . $ 16.801010
Commodity Charge 2/	$ 0.103390	Varies	Varies	per MCF	
Environmental Surcharge Rider	$0.01748		$0.01748	per MCF	
Public Utilities Tax			5.00%	Charged on all non-exempt services, including the GCR	
City of Wilmington Local Franchise Tax			2.00%	Charged on all non-exempt services, in the City of Wilmington, including the GCR	

1/ Gas used by Customers with permanently installed gas-fired space heating equipment qualifies for the space heating commodity rate for all gas used in excess of 50 ccf for the billing months of October through May, inclusive.

2/ All LVG and "Electing" MVG Customers pay a monthly Commodity Charge GCR based upon the system Weighted Average Commodity Cost of Gas ("System WACCOG"). "Non-Electing" MVG Customers pay the annual GCR Commodity Charge listed here.

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RATES AND CHARGES

CORE TRANSPORTATION RATE LEAF

SERVICE CLASSIFICATION	BASE RATE	NON-BASE RATE	BASIS
General Volume Firm Transportation Service ("GVFT")			
Customer Charge	$302.31		per month
Delivery Charge			
First 750 CCF	$ 0.349750		per CCF Redelivered
Over 750 CCF	$ 0.261250		per CCF Redelivered
Balancing Fee		$ 0.04242	per CCF of Imbalance Volumes
Environmental Surcharge Rider	$0.00175		per CCF
Medium Volume Firm Transportation Service ("MVFT")			
Customer Charge	$694.27		per month
Demand Charge	$ 13.39		per MCF of Billing MDQ
Delivery Charge	$ 0.429790		per MCF Redelivered
Balancing Fee		$ 0.4242	per MCF of Imbalance Volumes
Environmental Surcharge Rider	$0.01748		per MCF
Large Volume Firm Transportation Service ("LVFT")			
Customer Charge	$909.58		per month
Demand Charge	$ 8.247210		per MCF of Billing MDQ
Delivery Charge	$ 0.103390		per MCF Redelivered
Balancing Fee		$ 0.4242	per MCF of Imbalance Volumes
Environmental Surcharge Rider	$0.01748		per MCF
Standby Service ("SBS")			
Demand Charge		$9.5152	per MCF of Standby MDQ
Commodity Charge		Monthly System WACCOG per MCF (adjusted for losses and unaccounted-for)	
Public Utilities Tax		5.00%	Charged on all non-exempt services, including the GCR
City of Wilmington Local Franchise Tax		2.00%	Charged on all non-exempt services, in the City of Wilmington, including the GCR

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Docket No. — Effective with Usage On and After November 1, 2009

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RATES AND CHARGES

NON-CORE RATE LEAF

SERVICE CLASSIFICATION	BASE RATE	MIN RATE	MAX RATE	NON-BASE RATE	BASIS
Flexibly Priced Gas Service ("FPS")					
Commodity Charge 1/		Varies	N/A		per MCF
No Notice Swing Charge	$ 0.15000				per MCF Redelivered
Medium Volume Interruptible Transportation Service ("MVIT")					
Customer Charge	$590.00				per month
Delivery Charge (2)					
Option 1	$ 1.30000				per MCF Redelivered
Option 2		$0.01	$3.27		per MCF Redelivered
Option 3	Negotiable				per MCF Redelivered
Balancing Fee				$0.4242	per MCF of Imbalance Volumes
Large Volume Interruptible Transportation Service ("LVIT")					
Customer Charge	$775.00				per month
Delivery Charge (2)					
Option 1					
First 5,000 MCF	$ 1.30000				per MCF Redelivered
Over 5,000 MCF	$ 0.36000				per MCF Redelivered
Option 2		$0.01	$1.00		per MCF Redelivered
Option 3	Negotiable				per MCF Redelivered
Balancing Fee				$0.4242	per MCF of Imbalance Volumes
Quasi-Firm Transportation Service ("QFT")					
Customer Charge	Negotiable				per Month
Demand Charge	Negotiable				per MCF of MDQ
Delivery Charge (2)	Negotiable				per MCF Redelivered
Balancing Fee				$0.4242	per MCF of Imbalance Volumes
Public Utilities Tax				5.00%	Charged on all non-exempt services, including the GCR
City of Wilmington Local Franchise Tax				2.00%	Charged on all non-exempt services, in the City of Wilmington, including the GCR

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1/ Minimum Rate is the monthly system WACCOG plus losses and unaccounted-for, unless gas is acquired specifically for, plus $0.01 per Mcf.

2/ Minimum and maximum rates do not include the applicable $0.00000/Mcf charge on QFT, MVIT and LVIT.

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